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April 29, 2010

FILED
2010 APR 29 P 4:03
PUBLIC UTILITIES
COMMISSION

The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
465 South King Street, First Floor
Kekuanaoa Building
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Docket No. 2008-0273 – Feed-in Tariff ("FIT") Proceeding
Schedule FIT Tier 3 Tariffs and Agreement

Pursuant to the Commission's September 25, 2009 Decision and Order ("Decision and Order"), and October 29, 2009 Order Setting Schedule in the above-subject proceeding, Hawaiian Electric Company, Inc. ("Hawaiian Electric"), Hawaii Electric Light Company, Inc. ("HELCO"), and Maui Electric Company, Limited ("MECO")(collectively the "Hawaiian Electric Companies" or "Companies"), respectfully submit for Commission approval the following proposed documents:

1. Schedule FIT Tariff – Tier 3 – Oahu
2. Schedule FIT Tariff – Tier 3 – Hawaii
3. Schedule FIT Tariff – Tier 3 – Maui[1]
4. Schedule FIT Standard Agreement for Tier 3

I. Introduction and Summary

The Commission's Decision and Order sets forth detailed general principles for the implementation of feed-in-tariffs ("FIT") in the Hawaiian Electric, HELCO and MECO service territories. This includes but is not limited to discussion of the types and sizes of renewable energy projects that would be eligible to participate in a FIT program, the process for determining the rates to be paid under a FIT program, and the non-rate terms and conditions that should be a part of a utility FIT program. The Commission also directed the Hawaiian Electric Companies to develop reliability standards for each Company to define the circumstances in which FIT projects can or cannot be incorporated, and craft queuing and interconnection procedures that will minimize delays associated with numerous potential FIT projects.

[1] Tier 3 does not apply to Molokai and Lanai (Decision and Order at 46).

With respect to Tier 3 projects, the Commission determined that "[t]his size is for projects that are in many cases not behind-the-meter and are designed to export large amounts of electricity to the grid." (Decision and Order at 46) The Commission recognized that "the largest size tier, Tier 3, will have more complex issues to resolve...." (Id.) With regard to pricing, the Commission acknowledged the difficulty in assuming standardized interconnection processes for larger projects. (Decision and Order at 69) The Commission directed that the FIT contain a set cost for interconnection that is based upon the "typical interconnection costs usually borne by the developer." (Id.) According to the Commission, "the developer can then make the determination whether its project can proceed under the FIT rate. If a developer's interconnection costs are so high as to render use of the FIT uneconomical, it always has the option of negotiating a PPA with the utility." (Id.)

The Commission's statements regarding the complex issues to be addressed and the handling of interconnection costs in particular are consistent with the Commission's acknowledgement throughout the Decision and Order that while a FIT can provide a streamlined vehicle for the integration of renewable resources to the utility grids, such integration should not occur without adequate regard for impacts on system reliability, impacts on existing renewable resources, and the impact upon the utilities' ratepayers, which are all exacerbated at these project sizes.

As discussed more fully below, the Hawaiian Electric Companies' proposed Tier 3 FIT Tariffs comply with each of the Commission's directives as set forth in the Decision and Order. The Tier 3 FIT Tariffs, together with the Tier 3 Schedule FIT Agreement, provide a standardized and streamlined process for the procurement of renewable energy intended to reduce both the risk and cost associated with that process. The Tier 3 FIT Tariffs also support the procurement of renewable energy from "*typical or average*" projects that are "*reasonably cost effective*" as outlined in the Decision and Order (at 62). Accordingly, the Tier 3 FIT Tariffs do not attempt to support every possible project configuration or location or what have been described as "lowest common denominator" projects. Both the Tier 3 FIT Tariffs and Tier 3 Schedule FIT Agreement have been developed to fully comply with the Commission's directive to "*not interconnect projects that will substantially compromise reliability or result in an unreasonable cost to ratepayers or would lead to significant curtailment of new or existing renewable energy generators.*" (Decision and Order at 56). Indeed, significant effort has been made throughout this process to develop Tariffs and a standard offer agreement that will appropriately incent efficient, cost-effective and responsible project development while at the same time discouraging inefficient or unnecessarily costly projects or those which would seek to secure excessive profit at the expense of Hawaii ratepayers, as well as discouraging inefficient developers from filling the FIT queue.

Finally, the FIT energy payment rates for Tier 3 reflect both collaborative and interactive technical sessions and settlement communications in the proceeding. The result of

these efforts by the parties is the incorporation in the Schedule FIT Tariffs and Schedule FIT Agreement of both modified language and pricing proposed by the parties.

The Hawaiian Electric Companies remain firmly committed to move decisively away from imported fossil fuel for electricity generation and towards indigenously produced renewable energy. The Companies' proposed FIT Program, inclusive of this submission for Tier 3 level projects, will accelerate the addition of renewable energy from new sources and complements a host of other renewable resource procurement programs in existence and to be developed by the Companies to facilitate movement toward a renewable energy future for the State. The Companies look forward to implementation of the FIT Program on Oahu as soon as possible and to the integration of increased levels of renewable resources on the other island systems in accordance with the Commission's directives in this proceeding.

II. Procedural Background

On September 25, 2009, the Commission issued its Decision and Order adopting general principles for a feed-in tariff for Hawaii. On October 29, 2009, the Commission issued its Order Setting Schedule which established the procedural schedule for the remainder of this proceeding.

Pursuant to the Order Setting Schedule, the Hawaiian Electric Companies conducted a workshop on Tier 3 issues on March 10, 2010, which included the Hawaiian Electric Companies' distribution of the Black & Veatch public model[2] (also used for Tiers 1 and 2) as well as the rate assumptions that went into the Hawaiian Electric Companies' Tier 3 rate development, to the parties. This was followed by the informal exchange of proposed tariffs and contract forms, informal comments on those documents, information requests and responses filed on April 8, 2010 and April 22, 2010, respectively, as well as subsequent settlement communications through the April 21, 2010 settlement discussion conducted by the Hawaiian Electric Companies.

In parallel with these procedural milestones, the Commission issued its Order Approving Independent Observer Contract on January 29, 2010. The Hawaiian Electric Companies conducted technical sessions on queuing and interconnection procedures and reliability standards on January 19, 2010 and January 26, 2010, respectively. The Hawaiian Electric Companies followed up with the filing of its report on queuing and interconnection procedures on February 1, 2010 and its report on reliability standards on February 8, 2010.[3]

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[2] Black and Veatch Model distributed via email to Parties on March 10, 2010.

[3] By letter dated February 9, 2010, the Hawaiian Electric Companies provided further clarification to its February 8, 2010 reliability standards report. In response to the Commission's letter of February 19, 2010, the Hawaiian Electric Companies submitted its proposal to convene a Reliability Standards Working Group ("RSWG") on February 26, 2010. This was followed by the filing of the parties' comments on the Hawaiian Electric Companies' RSWG on March 15, 2010 and Hawaiian Electric Companies' Reliability Standards Working group plan on March 31, 2010.

This was followed by the filing of information requests and responses on queuing and interconnection and reliability standards on February 16, 2010 and March 1, 2010, comments on queuing and interconnection procedures on March 8, 2010 and comments on the Companies' reliability standards report on March 23, 2010.

III. Tier 3 Schedule FIT Tariff[4]

The following discusses the provisions of the proposed Tier 3 Schedule FIT Tariff and how the provisions are compliant and consistent with the Commission directives set forth in the Decision and Order.

Availability of Schedule FIT Tariff

Section A of the Tier 3 Schedule FIT Tariff generally provides that the Tariff is available to customers, individuals, and independent power producers who wish to sell electric energy from an eligible FIT facility to the Company. More broadly, however, the availability of the Tier 3 Schedule FIT Tariff must be consistent with the Commission's directives to the Companies to "*refuse to interconnect projects that will substantially compromise reliability or result in an unreasonable cost to ratepayers*" (Decision and Order at 44) (Emphasis supplied) and "*not interconnect projects that will substantially compromise reliability or result in an unreasonable cost to ratepayers or would lead to significant curtailment of new or existing renewable energy generators.*" (Decision and Order at 56) (Emphasis supplied)

As discussed above, the Commission has recognized that Tier 3 sized projects "are in many cases not behind-the-meter and are designed to export large amounts of electricity to the grid" and, due to their size, "will have more complex issues to resolve...." (Decision and Order at 46) Accordingly, availability of the Tier 3 Schedule FIT Tariff should ultimately be dependent upon a Commission determination for each island system that allowing Tier 3 projects to go forward would not be in conflict with the Commission's directives set forth above. As described in detail in the Companies' February 8, 2010 Report on Reliability Standards ("Report") and further clarified in the Companies' February 26, 2010 letter to the Commission, the system studies and evaluations discussed in the Report generally indicate that for Oahu, no significant system wide reliability or curtailment issues are expected with full implementation of FIT Tiers 1-3 up to the 60 MW program cap established in the Commission's Decision and Order. Further studies are being done to confirm the ability to interconnect more DG beyond this level.

Due primarily to the high level of existing and planned variable renewable resource penetration on the Hawaii Island and Maui systems, however, the ability to accommodate

[4] The provisions of the Schedule FIT Tariff are largely identical across islands. The provisions vary primarily due to the different project eligibility criteria applicable to each island pursuant to the Decision and Order.

additional variable renewable resources without causing significant curtailment of either existing or planned renewable resources, or impacting system reliability, is limited on those islands. As discussed in the Companies' February 26, 2010 response to the Commission's request for more information on the Companies' proposal to convene a Reliability Standards Working Group ("Working Group"), although the Companies are continuing to interconnect renewable projects on all islands, the Companies have proposed that implementation of FIT on the HELCO and MECO systems – both in terms of timing and scope – should be subject to review by the proposed Working Group. Notwithstanding this proposal, the Companies provide herein Tier 3 Tariff documents for HELCO and MECO, consistent with the Commission's Decision and Order.

Eligibility

At pages 31 and 32 of the Decision and Order, the Commission identified photovoltaic ("PV"), onshore wind, in-line hydropower, and concentrated solar power ("CSP") as technologies eligible for a FIT. At page 45 of the Decision and Order, the Commission set forth its determinations on project size tiers for the initial FIT. The Commission determined that Tier 3 project sizes would include projects greater than the Tier 2 maximums and up to and including the lesser of 5 MW on Oahu and 2.72 MW on Maui and Hawaii or 1% of the system peak load from the previous year, except that wind generation is precluded on Maui and Hawaii. Section B of the Tier 3 Schedule FIT Tariffs is compliant with the provisions of the Decision and Order with regard to the identification of eligible Tier 3 project technologies and sizes for Oahu, Maui and the Island of Hawaii.

During discussions with the parties to this proceeding, one of the issues that arose was whether there are in fact existing or planned in-line hydropower projects in the State of Hawaii that could avail themselves of the Tier 3 Schedule FIT Tariff. In addition to the lack of any Hawaii-specific data upon which to develop pricing for this technology, there is a question regarding the feasibility of an in-line hydropower project of this size in the State. As the Commission is aware, in-line hydropower for purposes of this proceeding has been defined as "hydroelectric generation that utilizes energy from a water pipeline system that is designed primarily to serve another functional purpose where a section of pipeline is replaced with a turbine-generator section. In-line hydroelectric generation does not include (a) pumped storage hydroelectric generation, (b) run of the river hydroelectric generation or (c) any system using the energy from water from a new (after January 1, 2009) diversion from any river or stream."

During the proceedings to develop Tier 1 and Tier 2 pricing, the Company had discussions with a consultant to the County of Hawaii water department regarding the County's plans for development of in-line hydro projects within their existing water system. The sizes of the potential in-line hydro projects were in the range of 10's of kWs to the lower 100 kWs. This is due to the fact that in-line hydropower project size is limited by the amount

of water flow and the height differential from the water source to the power generator. The County of Hawaii installed three in-line hydro projects in the 36 to 45 kW size range. The County of Maui Water Department similarly assessed its in-line hydropower project potential to be in the range of 10's of kWs to projects in the lower 100 kWs in size.

Tier 3 in-line hydropower (100 kW to 5 MW) projects are not known to exist at this time. All things being equal, the estimate of water pipe diameter in the Tier 1 and Tier 2 in-line hydro projects may be about 8 to 16 inches to maintain flow velocity. Tier 3 in-hydro project pipe diameters would have to be in the range of 24 to 60 inches in diameter to be feasible and these size pipes are not presently available for project development. Given this situation which the Hawaiian Electric Companies were not aware of at the time of their initial proposal in this proceeding, and the aforementioned uncertainty about whether representative pricing for FIT-eligible in-line hydro projects in Hawaii can be developed given current available information, the Commission may wish to consider deferring in-line hydropower projects eligibility for the Tier 3 Schedule FIT Tariff until the first FIT update. It is the Companies' understanding that there are a number of parties that are either in agreement with or would not object to this action by the Commission.

Section B also includes the following provision:

> *Except with the written consent of Company, which consent shall not be unreasonably withheld, each physical address (defined as a single residential address or a single tax map key if a commercial or industrial facility) may not have more than one Facility of the same technology type contracted under this Schedule FIT.*

The purpose of this provision is to prevent, to the extent possible, a developer from attempting to avail itself of the higher pricing which may be attendant to the smaller Tiers by developing a number of smaller Tier projects (thereby taking up the program capacity reserved for those Tiers) rather than a Tier 3 project at a particular site. The Hawaiian Electric Companies do not wish, however, to discourage or prevent any eligible renewable facility from participating in the FIT program. Accordingly, the provision allows the utility the opportunity to consent to participation by projects which are eligible but may be inadvertently restricted from participation by this provision.

Section B also contains provisions regarding the eligibility of certain existing facilities to participate in the FIT program including customers currently receiving service under the Companies' Net Energy Metering Program. These provisions are consistent with the Commission's determinations on these issues set forth at pages 20-22 of the Decision and Order.

Finally, Section B contains the following provision regarding the sale of electric energy and changes to the Schedule FIT Agreement which is compliant with the directives of the Decision and Order at pages 85-86.

> *Any Facility selling electric energy to the Company under this Schedule FIT shall sell all the electric energy it produces above any electric energy produced for Seller's own energy consumption, to the Company for the entire term of the Schedule FIT Agreement. A Seller may not sell electric energy to third parties or renegotiate with the Company for any changes to the Schedule FIT Agreement during the term of such Schedule FIT Agreement.*

Seller Participation

Section C describes the process for a Seller's participation in the FIT program and how that participation may be managed given that there is not an unlimited capacity on the island systems to take new, variable renewable generation. Section C recognizes and incorporates the role of the Independent Observer and the Commission in determining and approving the Companies' queuing procedures. This section is consistent with the provisions of the Decision and Order at pages 92-93.

Interconnection

At page 69 of the Decision and Order, the Commission recognizes the challenge in determining standardized interconnection processes for larger projects. Although it would be difficult to standardize the interconnection process for Tier 3 level projects, there are both industry and Company standards and procedures that would apply and Section D of the Tier 3 Schedule FIT Tariff, which expressly requires compliance with these interconnection standards and procedures is consistent with the Commission's Decision and Order.

Schedule FIT Agreement

Section E of the Tier 3 Schedule FIT Tariff requires that Sellers applying to participate under Schedule FIT complete and sign the standard Schedule FIT agreement appended to the Tariff. This is consistent with the Commission's determination that "*to the extent possible, the utility should provide standard offer contracts with commission-approved FIT rates and mandated terms and conditions*" as set forth at page 87 of the Decision and Order.

Metering

Section F of the Tariff concerns metering and delineates responsibility for the costs of metering between the Company and the Seller. The Section is consistent with the

Commission's determination that the Company should utilize Rule 14, Section H for guidance in establishing interconnection costs and standards, which would include metering.

Purchase of Renewable Energy Delivered by Seller to Company

There are a total of four rates to be adopted for Oahu corresponding to each of four eligible technologies in Tier 3. For Maui and the Island of Hawaii there are three rates due to the exclusion of wind as an eligible technology. (Decision and Order at 45)

Additionally, it is important to recognize the important role that tax credits (either the 35% state tax credit or the 24.5% refundable state tax credit) can play in the calculation of a rate, particularly for certain technologies such as PV and CSP. The 35% state tax credit results in lower costs to ratepayers and therefore the Hawaiian Electric Companies have assumed for each relevant technology full monetization of this tax credit. However, on an informal basis, other parties to this proceeding have presented project case study information describing the difficulties experienced to date with the ability of developers to monetize the 35% tax credit and indicating that use of the 24.5% refundable credit may be more probable.

As stated by the Commission in its Decision and Order, with respect to State and federal taxes and other incentives, the Commission agrees that "adjusting the project development costs for such tax credits, tax policies, rebates or incentives for renewables is consistent with the inclusion of the taxes incurred in the project development cost used in the determination of the FiT rates." (Decision and Order at 63). To the extent that parties in this proceeding are able to provide record support to the Commission for use of the 24.5% refundable credit, including but not limited to identification of Hawaii specific examples of this situation, the Hawaiian Electric Companies would support including a 24.5% refundable State tax credit rate for election by a PV or CSP developer upon an appropriate demonstration that this would be the relevant tax treatment for the project. The development of these two additional rates as well as the other four proposed rates to be adopted for the Tier 3 Schedule FIT Tariff for Oahu, and how these rates are compliant with the Commission's direction in the Decision and Order, are discussed in detail below.

Page 2 of the Decision and Order sets forth the fundamental guidance for the development of FIT rates: "FIT rates will be based on the project cost and reasonable profit of a typical project. The rates will be differentiated by technology or resource, size, and interconnection costs; and will be levelized." At page 62, the Commission reiterated that "FIT rates should support a typical or average project that is reasonably cost-effective," and that "included in the calculation of FIT rates should be project and generation cost information, energy production, and the target internal rate of return." At page 84 of the Decision and Order, the Commission noted that "the HECO Companies are responsible for developing the initial FIT rates in collaboration with the parties, and may employ independent consultants to assist them as needed in compiling cost of generation data and determining the

amount of energy produced by typical projects." The Hawaiian Electric Companies retained Energy and Environmental Economics, Inc. ("E3") and Mirenish Consulting ("Mirenish") to assist in development of the initial FIT rates.

In developing the initial FIT rates, E3 and Mirenish were informed by the following additional determinations contained in the Decision and Order: (1) "*FIT rates should vary by technology or resource type, and by project size*" (at 78); (2) the FIT "*will not feature different rates for each island*" instead, "*rates should cover the cost of and provide a reasonable return for typical projects on Oahu, although they will apply to other islands as well*" because "*uniform FIT rates across all islands better encourage developers to locate projects where they are least cost than would location-differentiated rate.*" (at 79); and (3) "*[i]n evaluating the justness and reasonableness of proposed FIT rates, the commission will look most favorably on those based on Hawaii-specific cost and performance data, followed by mainland cost and performance data*" (at 84).

Methodology, Process and Intent in Determining Rates

As noted above, the Commission's Decision and Order requested that the Hawaiian Electric Companies develop a cost of generation analysis to determine FIT rates that would "support a typical or average project that is reasonably cost effective." (Decision and Order at 62) Since every renewable project has unique characteristics, and it is therefore difficult to define any single project as "typical," the Hawaiian Electric Companies' pricing team[5] developed a range of illustrative and representative projects that span a range of levelized costs using varying capital cost, energy production (capacity factors), and other cost and operating inputs. The "typical" or average project is defined as the midpoint of this levelized cost range. The cost of generation analysis strikes an appropriate balance between support for typical or average projects that are reasonably cost effective and the desire to mitigate adverse ratepayer impacts.

The Companies sought to make the pricing process as transparent and collaborative as possible by providing a public and user-friendly simplified pro forma cost of generation model and offered numerous opportunities for the stakeholders to submit additional, and where available Hawaii-specific, benchmarking information given their policy and project development experience. For Tier 3, the Companies distributed the illustrative levelized cost of energy ("LCOE") model on February 9, 2010 and stakeholder input was solicited prior to the technical workshop on March 10, 2010. Stakeholder inputs were solicited again during and after the technical workshop in March, and after the settlement meeting on April 21,

[5] The Hawaiian Electric Companies' internal FIT pricing team included representatives from HECO, MECO, HELCO, and the Companies' renewable procurement, energy analysis and transmission and interconnection departments in particular. The FIT pricing team was supported by outside consultants, Energy and Environmental Economics, Inc. based in San Francisco, California ("E3") and Mirenish Consulting based in Hawaii.

2010. The Companies worked to incorporate all third-party verified data that was received and considered additional comments regarding Hawaii-specific development experience.

The overall intent was to develop Tier 3 FIT pricing that reflects typical projects that can be installed in Hawaii by efficient developers. For Tier 3, the Companies followed the same basic methodology used to calculate the rates for Tiers 1 and 2. First, the Companies reviewed available information on installed Hawaii projects within the size range for each technology. To provide a comprehensive range of inputs, the Companies also benchmarked mainland cost of generation numbers for all technologies within Tier 3 using public sources where available and manufacturer and developer quotes for major equipment. The mainland benchmarks were then adjusted for Hawaii premiums for shipping, labor and land cost. This is consistent with the Commission's directives regarding the process for determining rates. (Decision and Order at 84)

Next, the Companies developed project scenarios to obtain an inclusive range of levelized cost of energy estimates by technology. The project scenarios encompass the expected range of low, medium and high LCOE results. Each technology's LCOE analysis is sensitive to key project inputs that vary by technology. The Companies' analysis also provided an additional sensitivity analysis to inform decision making based on the key factor or factors that drive the LCOE. The results are FIT rates that balance support for increased renewable project development while protecting utility ratepayers from adverse rate consequences to the extent possible. While the Companies have provided detailed cost of generation analyses on the basis of current capital costs, financing, and other benchmarking inputs, it is also important to note that FIT programs in general are adopted in order to reduce barriers to development which will necessarily change the development environment. For example, new developers, investors, and lenders may be attracted to the State given the more streamlined FIT process and established market. In addition, the FIT program will expand the current market, and larger markets generally should encourage more efficient methods of procurement, construction, and financing.

Global Benchmarking Assumptions

Interconnection

Unlike Tiers 1 and 2, Tier 3 projects have additional interconnection costs because they are larger and require equipment for reliable interconnection to the electric grid. As a part of the rate development process, the Companies estimated interconnection costs for projects up to 1 MW, projects up to 2.5 MW, and projects up to 5 MW. These estimates come from the Hawaiian Electric System Integration Department, as well as equipment manufacturer quotes for transformers. The four main cost categories for interconnection are: (1) interconnection requirements study ("IRS"), (2) supervisory control and data acquisition

("SCADA") and Direct Transfer Trip (including communications equipment), (3) line extensions, and (4) transformers, breakers and protective relays.

	Projects up to 1 MW	Projects up to 2.5 MW	Projects up to 5 MW
IRS	$30,000	$45,000	$100,000
SCADA and Direct Transfer Trip	$500,000	$500,000	$500,000
12 kV or 46 kV Overhead Line Extension	(No Projection)	(1,000 feet, 12 kV) $100,000	(1,500 feet, 46 kV) $150,000
Transformers, breakers, and relays	(No Projection)	$80,000[6]	$525,000[7]
Total	$530,000	$725,000	$1,275,000

As presented, the included interconnection cost for a project up to 1 MW is $530,000. For projects up to 2.5 MW, the cost is $725,000, and for projects up to 5 MW the cost is $1.275 million.

These interconnection costs were added to the capital cost of each technology in the scenarios that have been run. It is important to note, however, that many of these assets do not receive all of the same tax-related benefits as other renewable resource equipment does because they are not classified to be eligible for those benefits. Consequently, for modeling purposes the interconnection line item is classified as a 20-year depreciation asset instead of a 5-year depreciation asset classification that assets such as renewable energy equipment receive through the Modified Accelerated Cost Recovery System ("MACRS").

The SCADA cost (including communications) is estimated based on the installation cost of equipment required due to the fact that Hawaiian Electric has not yet implemented SCADA for projects of Tier 3 size and therefore does not have actual installed cost data. However, the estimate is a Hawaii-specific one. The line extension cost is an average of all the projects Hawaiian Electric performed in 2009 and covers a general overhead line extension to serve customers. The IRS cost is based on actual studies completed for Hawaii PV projects. For Tier 3 size projects, the Hawaiian Electric Companies have completed two IRSs to date which were the Kona Commons (~$30,000) and the Koyo USA (~$27,000) projects which were both on the HELCO system and interconnected at the 12kV level. There are two other IRSs in progress on Oahu. For one of those projects, the consultant's cost for the IRS for a 5 MW project has been priced at $75,000 (plus 20 to 25% more for the Company's internal labor cost to administer and review the IRS as well as develop cost estimates for the interconnection facilities). The 46kV overhead line extension cost for that project is approximately $130,000 to $175,000 depending on the route alignment which is

[6] 2.5 MW Transformer: 2,500 kva, 12kV – 480V distribution transformer and associated breaker, protective relays, etc.

[7] 5 MW Transformers: 5,000 kva, 46 kV – 12 kV distribution transformer and five 1,000 kva, 12 kV – 480V transformers with associated breakers, protective relays, etc.

currently being evaluated. The IRS for this project is typical of a 5 MW project and has a short 46kV overhead line extension. For another project, the developer has paid $100,000 for the IRS. In addition, the 46kV line extension cost for that project is approximated at this time to be $886,000. This project, however, should not be considered "typical" and is not included as a FIT data point for the following reasons. First, the IRS for this project was done using a portfolio approach which consisted of several projects of different sizes, technologies, and locations. Secondly, the 46kV line extension is fairly lengthy (~1 mile) with a portion of it being underground. The cost for the line extension is higher than typical given the distance and the higher underground cost as compared to the typical overhead installation; therefore, it is not considered to be a representative cost for a typical FIT Tier 3 project.

Land

For PV and CSP technologies, the Companies assumed a land lease cost. Unlike for wind generating technologies, solar generating technologies fully occupy and use the land upon which they reside. There are very few, if any, alternative uses for the land available once a solar facility is installed. As such, it is typical in the solar industry to sign a land lease that reflects the full cost and use of the land, much like a farmer would. The range of land lease costs in Hawaii varies widely, but the range observed for properties that would most likely be developed with PV and CSP technologies was $5,000 - $15,000/acre/year. For scenario modeling for PV and CSP technologies, the mid-point of that range was used, $10,000/acre/year, for all project scenarios. In addition, the land lease cost is escalated at a rate of 3%/year, applied every five years. The chart below shows an example land lease over the 20 year period, increasing in cost every 5 years.

Example Lease Escalation - PV/CSP	
Years	*Lease*
1 - 5	$ 10,000
6 - 10	$ 11,593
11 - 15	$ 13,493
16 - 20	$ 15,580

For wind and hydro projects, a revenue lease structure was used whereby the lessor receives a certain portion of the project's revenue on an annual basis. Unlike with solar projects, the land upon which wind turbines are erected can maintain alternative uses, hence the different leasing structure. Oftentimes farmers will lease out their land underneath the wind turbine to a wind developer while at the same time continuing to farm the land around the turbines. The range observed in the wind industry is 2 - 4% of revenues on an annual basis, and that range is supported by the American Wind Energy Association ("AWEA"). The high end of the revenue lease structure range was used (4%) for the FIT modeling because land lease costs in Hawaii are generally higher than in the rest of the country.

Land lease costs for solar projects were derived from a number of sources. The only public domain information that the Companies have on land costs for specific renewable energy projects in Hawaii is from the Department of Hawaiian Home Lands ("DHHL"), discussed below. In addition, publicly-available costs for agricultural lands were used to establish the broader range of land lease costs. The two DHHL land lease proposals are outlined below and can be found at the following link on DHHL's website: http://hawaii.gov/dhhl/beneficiary-consultation/renewable-energy-projects-kalaeloa-oahu

Sopogy land lease proposal discussed at a public meeting on June 23, 2009 (http://hawaii.gov/dhhl/beneficiary-consultation/HHC%20D-5%20062309.pdf):

- $355,200 for 34 acres ($10,447.06/acre/year)
- Increases by 25% over year 1 price in year 10 ($444,000)
- Increases by 12.5% over year 10 price in year 16 ($499,500)
- Kalaeloa, Oahu

Recurrent Energy land lease proposal discussed at a public meeting on October 20, 2009 (http://hawaii.gov/dhhl/beneficiary-consultation/HHC%20D-4%20102009.pdf):

- $302,760 for 29.853 acres ($10,141.69/acre/year)
- Increases by 25% over year 1 price in year 10 ($378,450)
- Increases by 12.5% over year 10 price in year 16 ($425,756)
- Kalaeloa, Oahu

The broader range of $5,000 - $15,000/acre/year as a starting point for the range of annual land lease costs (the leases in the modeling are assumed to have an escalation of 3%/year added to the lease cost every five years – 16% above year 1 cost in year 6, 34% above year 1 cost in year 11, and 56% above year 1 cost in year 16) was gleaned from the Hawaii market using publicly-available costs. Because the two public solar leases fell in the middle of the range that was observed (~$10,000/acre/year – but at a lower escalator than the Companies assumed), that is the price that was assumed for all solar projects. The following data points are a sampling of what was used to determine the broader land cost range:

Kunia/Ewa large acreage:	$2,000/acre/year
Leeward side smaller acreage:	$7,000 - $15,000/acre/year
Kalaeloa Redevelopment (old Barbers Point NAS):	$10,500/acre/year

PV and CSP projects utilize a set $/acre/year lease metric, so in order to determine the total land lease cost per project one must assess how many acres a project will occupy. The assumed acreage requirements for modeling purposes are outlined below.

PV:
5 acres/MW for fixed tilt systems

7 – 9 acres/MW for tracking systems. The low end of the range is dictated by a flat (0 degree tilt) tracker and the high end of the range is dictated by a 20 degree tilted tracker.

The land requirements for PV are based on the necessary Ground Coverage Ratio (GCR) for PV system row placement given Honolulu's latitude (21 degrees) to prevent shading created by the shadows that panels can cast onto nearby rows. Trackers require more land than fixed tilt projects because they create longer shadows as they track throughout the day and therefore need to be spaced further apart.

CSP:
3 acre per 500kW for CSP trough projects
1 acre per 500kW for commercial Stirling Dish projects

The land requirements for CSP were taken from the 2006 NREL CSP Analysis by Black & Veatch which can be found at the following link: http://www.nrel.gov/docs/fy06osti/39291.pdf. The table from the report which shows the land resource requirements is provided below for your convenience.

Given that there are 640 acres per square mile and dividing the capacity potential by the land area, the land requirements are 5.7 acres per MW or rounding up, 3 acres per 500 kW for parabolic trough without storage. The land requirements for dish CSP are 5 acres per MW or 2.5 acres per 500 kW. However, dish manufacturers currently quote substantially lower land requirements and assume that some of the land remains usable for other purposes. The 1 acre per 500 kW assumption used in the pricing team's analysis was quoted by Infinia. The land requirements for concentrating PV are 6 acres per MW or 3 acres per 500kW.

Table 3-1
Concentrating Solar Power Technical Potential

	Solar Resource Land Area, mi^2	Capacity Potential, MW	Generation Potential, GWh
Parabolic Trough, no storage < 1 % slope	5,900	661,000	1,614,000
Parabolic Trough, six hours storage < 1 % slope	5,900	471,000	1,640,000
Power Tower, six hours storage < 1 % slope	5,900	342,000	1,233,000
Parabolic Dish, < 3 % slope	11,600	1,480,000	3,371,000
Parabolic Dish, < 5 % slope	14,400	1,837,000	4,196,000
Concentrating PV, < 3 % slope	11,600	1,235,000	2,859,000
Concentrating PV, < 5 % slope	14,400	1,534,000	3,558,000

Transparent Model

To develop the FIT rates, the Companies utilized a straightforward, public, LCOE model developed by Black & Veatch which has been thoroughly vetted through the California Energy Commission's Renewable Energy Transmission Initiative ("RETI") stakeholder process. That model can be found at http://www.energy.ca.gov/reti/documents/index.html. The Companies added the following elements to the RETI model to ensure that it appropriately conformed to the Hawaii market: Hawaii State tax credits, insurance, land costs, excise taxes, production degradation and tax rates (marginal federal rate and effective state tax rate) and assumed full monetization of all tax credits and depreciation. In addition, the Companies made a few minor modifications to the model that was used for Tiers 1 and 2. A construction financing module was added to take into account interest accrued during the construction phase of the project, because Tier 3 projects are larger and take longer to develop. The module is very simple and calculates the construction financing cost based on the total capital cost of the project and the construction timeline, and that interest is added back to the capital cost. As discussed earlier, the model was also amended so that interconnection capital costs are classified as 20-year depreciation assets as opposed to 5-year assets like other renewable energy assets.

There are basically two general ways to model a project's cash flow: the levered approach and the unlevered approach. The levered approach explicitly includes debt financing as a cost component, and provides a net after-tax cash flow from the project owner's, or equity investor's, perspective. The internal rate of return computed on these equity cash flows is essentially the return that the equity investor can expect over the life of the project, and therefore must meet the investor's required rate of return, or hurdle rate, in order for the investor to invest in the project. The levered approach therefore explicitly includes all costs relevant to the project, including financing costs, in order for the equity investor to evaluate the return on equity investment.

By contrast, the unlevered approach does not explicitly include debt financing costs, and instead yields total cash flows available to both debt and equity investors. The internal rate of return computed on these total cash flows is the overall project return which must meet the combined return expectations of both debt and equity investors in order for the project to be financed. The hurdle rate in unlevered cash flow modeling is therefore a combination of debt and equity return requirements, and is typically computed as a weighted average cost of capital which considers the proportion of debt and equity used to finance the project as well as the after-tax cost of debt and equity. Although debt financing in the unlevered approach is not explicitly included in the overall cash flows, it is implicitly considered in the hurdle rate.

Although both the levered and unlevered cash flow methods consider debt financing in some form, the levered model considers this project cost in a more direct manner. Since renewable energy projects are typically financed with a portion of debt, the Companies

contend that this cost should be explicitly recognized and included in the project cash flows as would be the case in the levered model. The Commission's Decision and Order also recognizes that debt financing is a component of project cost, and supports its inclusion for FIT pricing purposes. The Companies therefore recommend using the levered cash flow model to compute LCOEs for FIT pricing purposes.

Additionally, as individual projects will have very specific financing structures (partnership flip structure, sale-leaseback structure, etc.), the model used for FIT pricing is intended as a general model with reasonable assumptions to forecast project cash flows. In the event that an unlevered model is used, the resulting LCOE will likely be higher than what could actually be achieved in the market, especially if little or no debt is assumed in the target rate of return. That would result in a windfall to the developer and/or investor at the expense of the utility customers. As directed by the Decision and Order, the simple discounted levered cash flow model used by the Companies will result in "support[ing] a typical or average project that is reasonably cost effective." (Decision and Order at 62)

It is important to note that the California Public Utilities Commission ("CPUC") has used a levered cash flow model for many of their recent and future planning projects, including its Long-Term Procurement Plan ("LTPP") (http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/) that is currently underway, the RETI process that was completed in California (http://www.energy.ca.gov/reti/index.html) and is currently undergoing a phase II analysis, and the CPUC's 33% Renewable Portfolio Standard Implementation Analysis (http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/33implementation.htm).

Financing

Financing costs can range widely depending on factors such as technology, size, and project location. The chart below provides a range of possible financing terms for renewable energy projects. In addition, on the far right of the chart are the assumptions that have been used for modeling the project scenarios, which are the same as the inputs that were used for Tiers 1 and 2. Because the construction debt module has been added to the cash flow model for Tier 3 projects, an additional category of financing assumptions has been used.

	Range		Input
Equity	Rate:	10 – 15%	11%
Permanent debt	Rate: Tenor: Percentage:	8 – 10% 15 – 20 yrs 30 – 40%	9% 20 yrs 35%
Construction debt	Rate: Term:	10 – 12% 4 mo – 1 yr	11% varies

Financing terms can change quickly depending on the financing climate and are generally not publicly available. These financing benchmarks were primarily obtained through the pricing team's conversations with developers and financiers who are heavily involved in the renewable energy industry. In addition, they were checked against other public processes in California and elsewhere.

Equity returns can range from 10 – 15%, which is slightly above a typical approved utility rate of return. In various California processes (RETI, CPUC 33% Analysis, LTPP, an equity rate of return within that range has been used. A return of 11%, at the lower end of the range, was used due to the fact that a FIT program, by design, will reduce risks to the developer, as well as the fact that the counterparty to FIT program transactions is a utility with an investment grade credit rating.

The permanent debt rate can range from 8 – 10%. In the RETI process in California a rate of 7.5% is used (http://www.energy.ca.gov/reti/index.html), and a rate of 7.3% is used for solar in the CPUC's 33% Renewable Portfolio Standards ("RPS") Analysis (http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/33implementation.htm). The Companies utilized a 9% rate due to the relative difficulty of raising debt financing in Hawaii. As such, the 9% debt rate can be viewed as conservative.

Debt tenor can extend over a 15 to 20 year period, or longer, if the agreement to be executed contains a longer term. The 33% RPS Analysis completed by the CPUC uses a 20 year debt term to calculate the levelized cost of energy (http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/33implementation.htm), and the CPUC is using that same assumption in their current LTPP which is in process (http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/). A 20 year period is used by the Companies.

The debt percentage of a capital structure can vary with the amount of cash generated by the project itself, but the typical range is 30 - 40%. The Companies have used 35%, the middle of that range for modeling purposes. It is important to note that the RETI process assumes a 60% leveraged scenario for modeling purposes (http://www.energy.ca.gov/reti/index.html). In the 33% RPS analysis the CPUC assumes a 45% leveraged scenario for modeling purposes (http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/33implementation.htm); and in the California LTPP currently underway the leverage ranges from 40 - 50%. The lower percentage of assumed leverage for the Hawaii FIT projects is to account for the fact that the financing environment in Hawaii is more difficult than on the mainland, but the 35% leverage can still be viewed as conservative. Even with the projects on the mainland, however, there is very little public data available on the capital structure of transactions as the information is proprietary. As such, the Companies evaluated the experience in California as a means of checking the validity of their input assumptions.

Finally, construction debt rates typically range from 10 – 12%. The Companies utilized a rate in the middle of the range, 11%. The construction timeframe varies by technology, is based on observed project construction timeframes, and is included in the specific model scenario runs attached to this document.

State Tax Credits

For purposes of the pricing development process, the Companies have assumed that the project owner will structure the project to take full economic advantage of the Hawaii renewable energy technologies income tax credits ("RETITC"). This is provided for in the Commission's Decision and Order which states on page 63 that the Commission agrees with the Department of Business, Economic Development and Tourism ("DBEDT") that "adjusting the project development costs for such tax credits, tax policies, rebates or incentives for renewables is consistent with the inclusion of the taxes incurred in the project development cost used in the determination of the FIT rates." Assuming a business structure that does not fully utilize available tax credits would provide subsidies for suboptimal business arrangements to the detriment of utility customers.

The State of Hawaii basically offers two corporate tax credits for renewable energy systems, a 35% investment tax credit for solar energy systems, and a 20% investment tax credit for wind energy systems (Hawaii Revised Statutes §235-12.5). Both of these tax credits are capped at $500,000 per "system." Although the statute defines "solar or wind energy system" as a separate and identifiable facility, equipment, apparatus, or the like that converts insolation or wind energy to useful thermal or electrical energy for heating, cooling, or reducing the use of other types of energy that are dependent upon fossil fuel for their generation, this definition has caused uncertainty among investors as to what actually constitutes a "system" for tax credit purposes. The Hawaii Department of Taxation ("HDOT") has issued some guidance on this issue in the form of a Tax Information Release

("TIR") 2007-2 (September 17, 2007) in which many examples of what constitutes a "system" were included, but these were relevant to photovoltaic systems only. This TIR did not address wind or CSP facilities in its examples, but the HDOT seemed to indicate that it would determine what constituted a separate and independent "solar energy or wind system" for RETITC purposes by looking at the ultimate product of the system, i.e., whether it generates power, provides industrial heat, or both (hybrid).[8]

Based on the HDOT's TIR, the Companies have used the following definitions of "system" for purposes of applying Hawaii tax credits to the prescribed technologies in their FIT pricing:

1. PV: a system consists of each set of PV panels and inverter that converts solar energy into useful electric energy

2. Wind: a system consists of each wind turbine generator ("WTG") since each modern WTG has its own electric generator and the output from each nacelle and tower base is useful electric power

3. CSP:

a. Solar dish - a system consists of each dish array which is typically designed with an electric generator at the focal point of the mirrors

b. Concentrating PV - a system consists of each concentrating PV panel that includes an inverter at its base

c. Solar trough - a system consists of each separate solar field/turbine generator facility that can independently produce electric energy

In addition to the above state tax credits provided in HRS §235-12.5, Hawaii also provides for a refund option only for solar energy facilities under Act 154 (2009). Under this new law, a taxpayer may elect to receive 70% of the 35% RETITC as a refund, or 24.5% of the cost of a solar energy facility in lieu of the full 35% RETITC. A taxpayer who has no state income tax liability may elect this refund option in order to monetize 70% of the solar energy tax credit.

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[8] See, TIR No. 2007-02, page 4: "The key to answering the question of whether any installation of renewable energy technology constitutes the installation of one or more systems, therefore, depends upon identifying the facility, equipment, apparatus or the like that is converting insolation or wind energy into useful thermal or electrical energy for heating, cooling, or reducing the use of other types of energy that are dependent upon fossil fuel for their generation. A system will only exist when all the components necessary for the conversion of insolation or wind energy into useful thermal or electrical energy are present..."

The specific state tax treatment for each technology is included in the financing assumptions and impacts the final LCOE.

Technology Benchmarking Assumptions

A detailed description of the benchmarking assumptions for each of the technologies is provided below as well as a description of the scenario results and resulting FIT proposal. In addition, a soft copy of the LCOE model for all the scenarios and all the technologies is included with this filing for the proposed rates[9]. This comprehensive background should provide all the information in a transparent and accessible manner.

It should be noted that some of the proposed FIT Tier 3 prices are near or slightly higher than those for Tiers 1 and 2. While this may seem counter-intuitive, there are reasons for these "reverse economies of scale" in Hawaii. Generally, for renewable energy projects, as the project size increases the capital cost decreases on a $/kW basis. However, in Hawaii, there are additional development costs that can counteract those economies of scale for capital costs. First, land lease costs in Hawaii are a significant portion of the operating budget of ground-mounted renewable energy projects. In Tiers 1 and 2, it was assumed that solar projects are roof-mounted and subject to a lower roof rental rate. Tier 3 CSP and PV projects are assumed to be ground mounted. In addition, interconnection costs can be very high for Tier 3 projects. Further, additional development costs for larger projects for all technologies can burden the project in a significant manner on a $/kW basis, thereby putting upward pressure on the resulting LCOE.

PV Benchmarking

Capacity Factor Assumptions

The capacity factor assumptions for Tier 3 changed from Tiers 1 and 2 because of the assumed system configuration for Tier 3 projects. Unlike Tier 1 and 2 projects which were assumed to be roof-mounted because of the size of the projects (0 – 500 kW), Tier 3 projects were mostly assumed to be ground-mounted with only the very low end of the capacity factor range being dictated by a flat, fixed-tilt project. As such, the range of capacity factors for different types of system configurations change accordingly.

For Tier 1 and 2 projects, it was assumed that the range of capacity factors for roof-mounted systems was between 16% and 17%. These numbers were calculated using the National Renewable Energy Laboratory's ("NREL") PV Watts 1 tool (solar production estimator model) with Honolulu as the location, a 180 degree azimuth angle, a direct current ("DC") to alternating current ("AC") derate ranging from 79 to 80%, and a tilt of 0 degrees to 10 degrees. For Tier 3 projects, there were two types of system configurations modeled. As

[9] Copies of the LCOE model will be provided to the parties via electronic distribution.

in Tiers 1 and 2, all Tier 3 capacity factors were calculated using NREL's PV Watts 1 tool (http://rredc.nrel.gov/solar/calculators/PVWATTS/version1/) with Honolulu as the location and a 180 degree azimuth angle. PV Watts 1 uses the Typical Meteorological Year 2 ("TMY2") data set for the purposes of forecasting production for PV systems all over the United States. The first type of system configuration modeled within the Tier 3 project size range is a fixed tilt system, and those capacity factors ranged from 16% to 17.3%. The low end of the range was assumed to be a 0 degree tilt system with a DC → AC derate factor of 78.2%. The high end of the range is assumed to be a 20 degree tilt angle and an 80% DC → AC derate. The second type of system configuration modeled within the Tier 3 project size is a tracking system, and those capacity factors ranged from 21% to 22.7%. The low end of the range was assumed to be a 0 degree tilt single-axis tracker with a 76.3% DC → AC derate. The high end of the range was assumed to be a 20 degree tilted single-axis tracker with an 80% derate. These capacity factors were also checked against NREL's Solar Advisor Model ("SAM") for Honolulu, and they were consistent.

These capacity factors are just one of the inputs that provide a range of resulting LCOEs, and the proposed FIT tariff is based on the mid-point of that range. Thus, while there are certain capacity factors that correspond with certain size projects in the model, that is not the only capacity factor a project of that size could have. The intent of the modeling was to put upper and lower bounds on the range of reasonable Tier 3 projects.

Capital Cost Assumptions

The pricing team worked to get capital cost numbers from public sources, but there is not much available publicly on this topic specifically in the 1 – 5 MW range. There is a good database of installed project costs through the California Solar Initiative database (http://eetd.lbl.gov/ea/EMS/reports/lbnl-2674e.pdf), but those projects are 1 MW and below and the numbers are fairly stale; particularly given the significant drop in module costs in 2009 and the first part of 2010. In addition, there are a few studies on cost of generation for larger projects, such as the RETI process that is underway in California, but those are for projects of 20 MW in size. As such, the Companies utilized PV quotes from manufacturers and developers to obtain a good range of installed costs for projects on the mainland. For many of the operating assumptions, the pricing team secured these from independent engineering estimates (operating & maintenance ("O&M") and degradation numbers). Insurance costs were based on insurance quotes, because it was very difficult to get publicly available information for Hawaii.

As with Tiers 1 and 2, the Companies needed to account for the increased cost of doing business in Hawaii (PV projects in Hawaii are generally more expensive than PV projects in California). As such, a 50% labor premium was added to the labor portion of the Balance of System of the Capital Cost. That premium was obtained from HECO's Integrated Resource Planning-3 process ("IRP-3") from May 2005 (Black & Veatch IRP-3 supply-side

portfolio update report) and is calculated based upon a combination of labor wage and productivity adjustment factors. The Companies kept inverter and panel prices the same as mainland prices but added the State excise tax to them. The resulting range of capital costs, including interconnection and permitting, was $4.27/watt dc to $5.70/watt dc for fixed tilt systems and $4.67 to $6.10/watt dc for tracking systems.

As noted with regard to Tiers 1 and 2 and in general, capital cost typically decreases as the PV project size becomes larger. Because of these issues surrounding economies of scale for PV projects, the Companies focused on projects of 2 - 4 MW in size within the Tier 3 range ($4.34 - $5.20/watt dc for fixed tilt and $4.74/watt dc to $5.60/watt dc for tracking systems). The Companies focus is on capturing economies of scale in capital cost without sacrificing the ability to deploy the full range of project sizes under the FIT for the benefit of their customers. Developers are still able to develop the full range of Tier 3 projects (500 kW – 5 MW). However, these projects will need to maximize efficiency so as not to overly burden ratepayers.

From the capital cost benchmarking table, the Companies re-adjusted the capital cost numbers to reflect typical projects within the 2 – 4 MW range, and those are the numbers that were used to run the scenarios presented below. The Companies ran scenarios within the Tier 3 range, varying size, cost, configuration and a few others factors (capacity factor, O&M costs, etc.). Permitting costs were provided in a detailed memo by Planning Solutions titled "Feed-in Tariff Tier 3 Pricing Development: Permitting and Environmental Factors." (Attachment B). This memo was also sent to the parties on March 10, 2010. The Companies modeled all of the PV projects at the high end of this range because they will *likely* disturb more than 1 acre of ground and a Notice of Intent - Construction ("NOI-C") will need to be filed. Therefore, all projects use $75,000 for their assumption on permitting costs.

Low end of the range:

- Less than 1 acre of land disturbance
- Private property
- Within the state-classified urban, rural, or agricultural districts
- Does not require the disturbance of high-value habitat
- Served by existing roads and transmission

Medium part of the range:

- Environmental assessment is needed
- No "substantial" land disturbance is involved
- No cultural impact assessment is required
- No special studies required because of noise or traffic

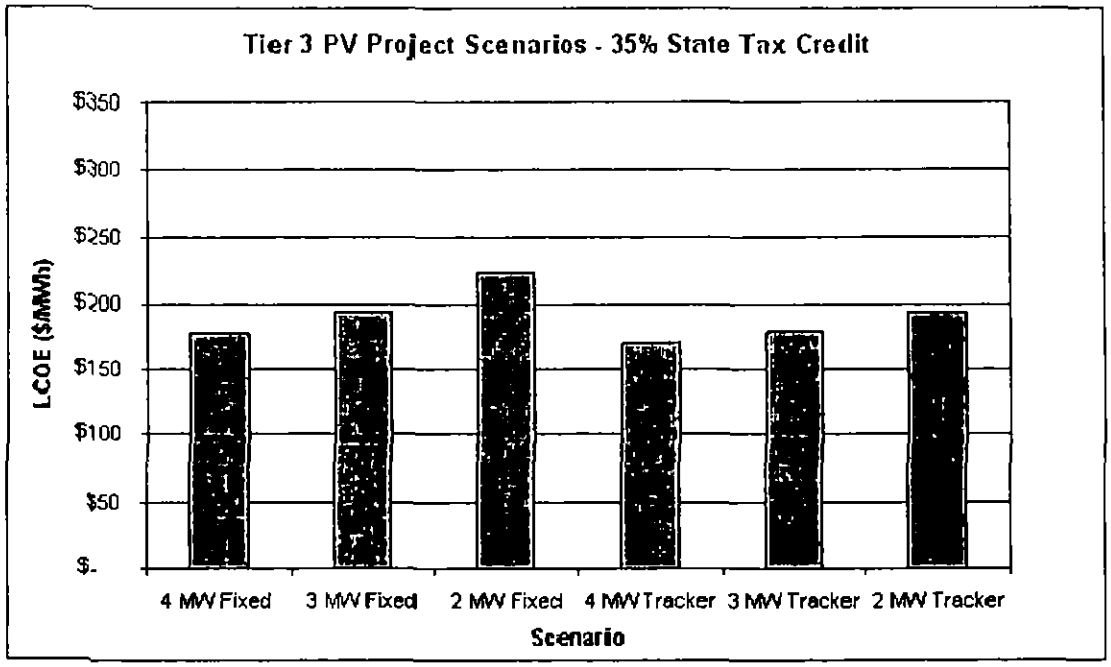
High end of the range:

- More than 1 acre of ground is disturbed, so a NOI-C needs to be filed with the State Department of Health
- Preparation of a Chapter 343 Environmental Assessment is necessary
- A moderate amount of other work is required

The Planning Solutions memo does not include the legal costs associated with securing permits. However, the transaction costs for project development (including legal fees) are included in the Balance of System or development benchmarking costs for all technologies.

Pricing scenarios

The resulting LCOE for Tier 3 PV projects ranges from $169/MWh on the low end to $224/MWh on the high end. These numbers assume the full monetization of all available incentives including tax credits at the federal and state level. The pricing proposal is the mid-point of the range of scenarios, not the average or median. The intention was to cap the upper and lower bounds of project scenarios and use the mid-point. The proposed FIT rate for Tier 3 PV projects of $197/MWh comes from taking the average of the bottom of the range (in this case the 4 MW tracker project at $169) and the top of the range (in this case the 2 MW fixed tilt project at $224). The graph of the 35% state tax credit scenarios modeled is included below.



Key Inputs	4 MW Fixed	3 MW Fixed	2 MW Fixed	4 MW Tracker	3 MW Tracker	2 MW Tracker
Size (kW)	4,000	3,000	2,000	4,000	3,000	2,000
Capacity Factor (%)	17.3%	16.7%	16.0%	22.7%	21.9%	21.0%
Installed Cost ($/W)	$ 4.34	$ 4.67	$ 5.20	$ 4.74	$ 5.07	$ 5.60
LCOE ($/MWh)	$ 177	$ 194	$ 224	$ 169	$ 178	$ 195

Assuming a 24.5% refundable state tax credit, the LCOE for Tier 3 projects ranges from $200/MWh on the low end to $271/MWh on the high end. $236/MWh is the midpoint of this range and is the proposed FIT rate for Tier 3 PV projects when using the refundable state tax credit at 24.5%. Lastly, the proposed FIT prices when modeling a 15-year debt tenor would be $209/MWh assuming a 35% state tax credit and $248/MWh assuming a 24.5% state tax credit.

Proposed FIT Rate

The proposed FIT rate for Tier 3 PV projects depends upon the state tax credit used. The Hawaiian Electric Companies propose a FIT rate of **$197/MWh** for projects that utilize the 35% state tax credit and **$236/MWh** for projects that utilize the 24.5% refundable state tax credit.

Wind Benchmarking

The five wind scenarios modeled represent generic installations to provide a range of LCOE costs. There are hundreds of combinations of turbines, towers and site development and installation costs. The scenarios are meant to be representative not all inclusive. It is assumed that the site development and construction costs are inversely related to the size of the system particularly in Hawaii where siting and installation present unique challenges. Smaller turbines are easier to transport and erect. Larger turbines may require specialized cranes (which may need to be shipped from the mainland) and additional road construction, geotechnical, and site work. Thus, the benefit of scale is reduced for larger turbines.

Capacity Factor Assumptions

A hub height of 50 meters ("m") was the default assumption used for calculating the capacity factor range. Stakeholders have suggested using a 10 m height and 12 miles per hour ("mph") wind as the default assumption. This is overly conservative. Most of the turbines considered can be installed onto towers between 40 m-70 m in height. The assumption of 12 mph measured at 10 m converts to around 15 mph at 50 m. The assumption of 12 mph wind at 10 m would be assumed to be Class 3 wind. Generally Class 3 wind is viewed as the low end of developable wind sites. Developers usually target wind classes of 4 or above or very low cost projects in Class 3 resources. The table below is from the AWEA website (http://www.awea.org/faq/basicwr.html) and shows the definition of the wind power classes and their associated wind speed at 10 m and 50 m. Measurements are often taken at 10 m, but, for energy production purposes those should be translated to the 50 m hub height level.

Wind Power Classes	10 m (33 ft)		50 m (164 ft)	
	Wind Power Density (W/m^2)	Average Wind Speed m/s (mph)	Wind Power Density (W/m2)	Average Wind Speed m/s (mph)
1	0-100	0-4.4 (0-9.8)	0-200	0-5.6 (0-12.5)
2	100-150	4.4-5.1 (9.8-11.5)	200-300	5.6-6.4 (12.5-14.3)
3	150-200	5.1-5.6 (11.5-12.5)	300-400	6.4-7.0 (14.3-15.7)
4	200-250	5.6-6.0 (12.5-13.4)	400-500	7.0-7.5 (15.7-16.8)
5	250-300	6.0-6.4 (13.4-14.3)	500-600	7.5-8.0 (6.8-17.9)
6	300-400	6.4-7.0 (14.3-15.7)	600-800	8.0-8.8 (17.9-19.7)
7	400-1,000	7.0-9.4 (15.7-21.1)	800-2,000	8.8-11.9 (19.7-26.6)

Capacity factors were derived from NREL's 2008 Mid-Scale Wind Study, "An Analysis of the Technical and Economic Potential for Mid-Scale Wind", by Kwartin,Wolfrum, Granfield, Kagel and Appleton published in 2008. (http://www.nrel.gov/wind/pdfs/midscale_analysis.pdf). The study provides energy production by wind class and turbine for several turbines within the Tier 3 size range. The Companies' analysis focused on the turbines above 100 kW to 1 MW in size. The system sizes (assuming multiple turbines) used for the analysis range between 1 MW to 5 MW[10]. The study showed capacity factors ranged from 26%-46% for Wind Class 4-7. The Mid-Scale Wind study looked at the Fuhrlander FL 250, Vestas V39, Norwin 46-ASR 750 and the Nordic 1000. The Vestas V39 is no longer available and therefore the HECO pricing team looked at the power curve and predicted output for the Vesta V52 which fell within the range of capacity factors developed in the Mid-Scale Wind study. The HECO pricing team also reviewed the he updated version of the Norwin, the Norwin 47-ASR 750, which has better performance characteristics than its predecessor with capacity factors for 7m/s-8m/s wind speeds from (30%-38%). The wind class range modeled in the cost of generation analysis ranged from 28%-36% (representing Class 4-6 wind). This range was chosen looking at wind resources and wind speeds from the Oahu specific wind resource map at 50 m. This resource map can be accessed here: http://www.state.hi.us/dbedt/ert/wwg/windy.html#oahu. In comments and discussions, stakeholders supported this capacity factor range.

Capital Cost Assumptions

Turbine prices were taken from several sources including the 2008 Wind Technologies Market Report, which is the most recent comprehensive public data source. The report was

[10] The pricing team considered modeling a 500 kW system, however it was determined that it is unlikely that the cost of a 500 kW system would be substantially different on a cost per kW basis than a 1 MW project given the assumption that smaller turbines are used in the 1 MW system not one 1 MW turbine.

published in July 2009 and is available at the following link: http://eetd.lbl.gov/ea/emp/reports/2008-wind-technologies.pdf. The report provides a range of turbine pricing for projects less than 100 MW at $1500/kW-$2000/kW. The pricing team also reviewed the KEMA California Energy Commission Cost of Generation Study ("CEC COGS") which specifically assessed community wind projects with sizes ranging from 100kW – 10 MW. The KEMA study did not specifically quote turbine prices but stated that turbine prices are usually 75% of total cost. The installed cost range was $2000/kW-$4000/kW, leading to a turbine cost range of $1500/kW-$3000/kW. The KEMA CEC COGS can be found here: (http://www.energy.ca.gov/2009_energypolicy/documents/2009-0825_workshop/presentations/05_KEMA_Building_and_Community_Scale_Renewable_Technology_Costs.PDF). The NREL 2008 Mid-Scale wind study also provided turbine quotes although some of those turbines are no longer available for sale. The range for turbines within the size range (250kW-1MW) was $1,700/kW-$2,400/kW again assuming turbine costs are 75% of total costs. The pricing team obtained a recent quote for a WES 250 kW turbine which was $2,360/kW (see Attachment A – WES 30 quote). The WES 250 kW turbine is one of the smallest turbines in the range reviewed and should be at the higher end of the price per kW scale. However, the pricing team conservatively modeled the middle of the range for turbine costs for the FIT pricing scenarios, $2000/kW-$2600/kW. In addition, the pricing team added freight and excise tax costs. Freight costs assume a shipping cost equal to 5% of turbine cost (which is from the Black & Veatch IRP-3 supply-side portfolio update report) and an excise tax of 4.72%.

Site development and installation costs were taken from the KEMA CEC COGS (see link above) which focused on community scale wind projects within this range. The KEMA study assumes installation and development costs represent 25% of the total installed cost or roughly $500/kW - $1000/kW. The pricing team then added the Hawaii premium which led to a range of ($750/kW-$1500/kW). In addition, a specific installation cost estimate from a 250 kW WES turbine was examined, which was $1020/kW (See Attachment A – WES 30 quote). The pricing team's scenarios conservatively modeled installation costs from $1100/kW to $1500/kW.

Permitting costs are provided in a detailed memo by Planning Solutions (Attachment B). This memo was sent to the parties on March 10, 2010. Wind permitting costs range broadly from $15,000 to $500,000. The low cost projects would be small projects on private property which do not disturb high value habitat and are served by existing roads and transmission. The medium scale costs would require an environmental assessment, health department or water resource permits, and some environmental field work. The high end cost includes a habitat conservation plan, incidental take permit, greater than one acre of land disturbed and a Chapter 343 environmental assessment. The pricing team conservatively chose the high end of the permitting cost range $500,000 or $100/kW-$500/kW depending on the project size. The Planning Solutions memo does not include the legal costs associated with

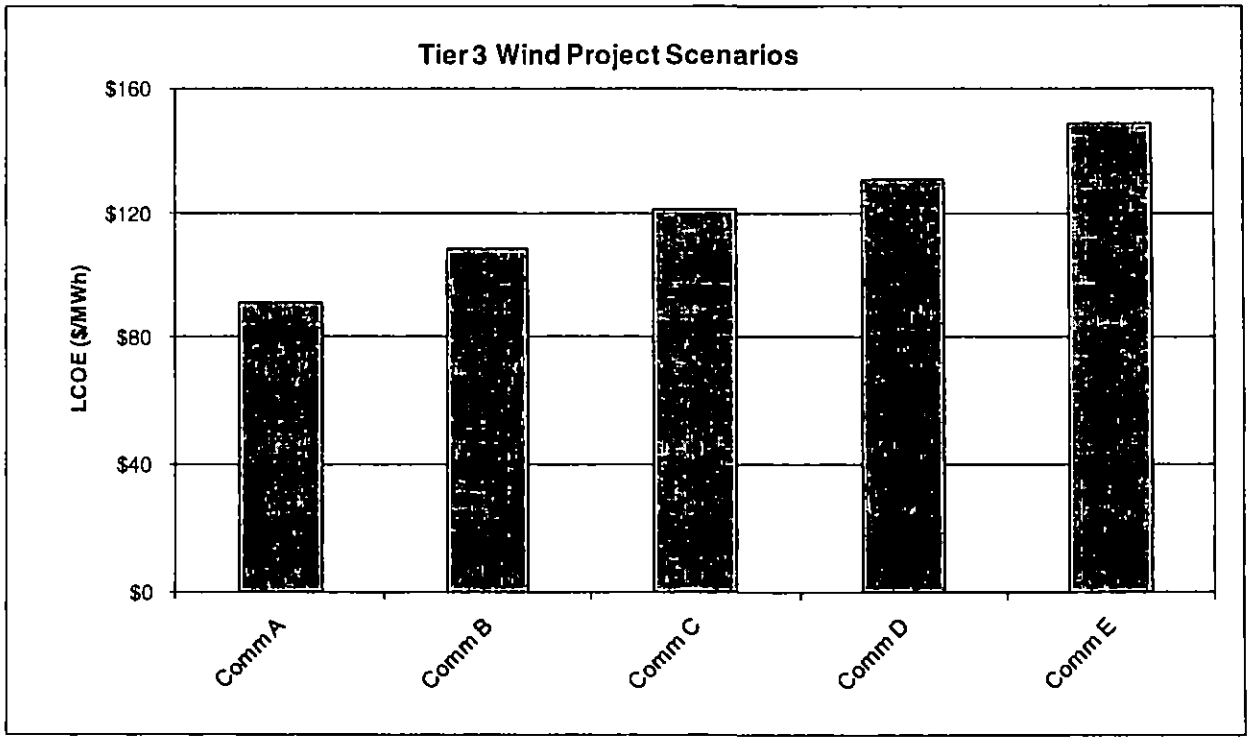
securing permits. However, the transaction costs for project development (including legal fees) are included in the development benchmarking costs.

In addition to turbine costs, freight & excise tax, installation & development costs, and permitting costs, the pricing team also included interconnection cost assumptions as a separate line item. The interconnection cost assumptions are the same across technologies. Depending on the project size they range between $255/kW-$530/kW.

The total installed costs modeled were between $4000/kW and $5000/kW. To put these costs into perspective, the final range of installed cost for community wind projects under the CEC COGS was $2000 - $4000 and the NREL Mid-Scale Wind study had installed costs ranging from $2300-$3200 for the turbine sizes reviewed. Thus, the final installed cost range for Hawaii represents a substantial premium.

Project Scenarios

With these assumptions and assuming that the state tax credit is fully monetized with multiple systems, the project scenarios range from $91/MWh at the low end of levelized cost to $149/MWh at the high end. The midpoint is the Companies' proposed FIT rate, at $120/MWh. The graph showing the scenarios modeled is included below.



Key Inputs	A	B	C	D	E
Size (kW)	5,000	5,000	2,500	1,000	1,000
Capacity Factor (%)	36%	34%	32%	30%	28%
Installed Cost ($/kW)	$ 4,049	$ 4,059	$ 4,314	$ 4,863	$ 4,983
LCOE ($/MWh)	$91	$109	$121	$131	$149

As described in the discussion of state tax credits in the general benchmarking assumptions above, wind projects are eligible for the state tax credit. The tax credit is capped at $500,000 per system. The HDOT, on page 3 of its TIR No. 2007-02, has defined a "wind-powered energy system" as "an identifiable facility, equipment, apparatus, or the like that converts wind energy to useful thermal or electrical energy..." Since each wind turbine produces AC power, it is believed that multiple systems will be applicable for wind projects (depending on the number of turbines installed). If after reviewing the state tax code further or from developer feedback from project experience the Commission determines that the state tax credit cannot be fully monetized the FIT rate would be $146/MWh (assuming one system and a cap of $500,000).

As noted above, the Hawaiian Electric Companies believe there are sound bases for a 20 year debt term including the experiences in California as well as the transformative nature of a FIT program on market dynamics. Nevertheless, the Companies have run an illustrative 15 year debt term scenario in the event that the Commission determines that 20 year debt is not viable even under a FIT program as is the documented HECO assumption and supported in the general benchmarking section. A 15-year debt term would lead to a FIT rate of $127/MWh with the state tax fully monetized and $153/MWh (with one system).

Proposed FIT Rate

The proposed FIT rate for Tier 3 wind projects is **$120/MWh.**

CSP Benchmarking

In an effort to be inclusive in the establishment of pricing for the CSP category, the Companies included three types of CSP technologies (all of which produce energy from the sun) in the cost of generation analysis: concentrating photovoltaic systems ("CPV"), parabolic trough systems ("Trough"), and Stirling dish systems ("Dish"). The Companies presented this group of concentrating technologies to the parties in November, 2009 and no party objected to the identified technologies when they were introduced.

Capacity Factor Assumptions

The Hawaiian Electric Companies derived the capacity factor for CSP technologies in Hawaii using public sources since no commercial facilities are installed on Oahu. The Companies used capacity factors for trough systems from the 2009 RETI assumptions which

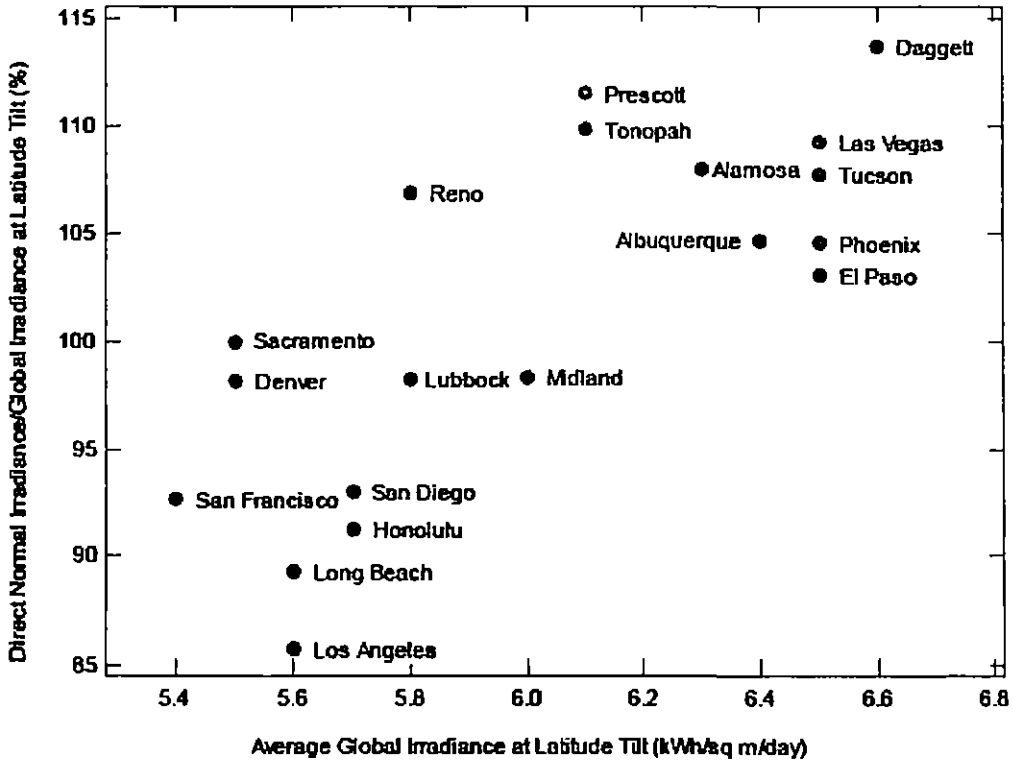
reviewed projects in the Western Electricity Coordinating Council ("WECC") region. The capacity factor range for projects within this region ranged from 20%-28% for dry cooled projects (previously the range was 22-32% for wet cooled projects). The 2009 update to the RETI assumptions can be found here: http://www.energy.ca.gov/reti/steering/workgroups/phase2A_update/2009-11-19_meeting/RETI_Phase_2B_WG_Presentation_2009-11-19.pdf.

However, the direct normal insolation ("DNI") in Hawaii is not as strong as in other areas of the western states. A Hawaii specific solar study from 1992 showed that for trough-based systems the reduction in DNI on the aperture plane was roughly 25% for Hawaii as compared to the best solar resources in the California Mojave Desert. See table III-6 in the study (Solar Thermal Electric Generating System (SEGS) Assessment for Hawaii) which can be found on the DBEDT publications website (http://hawaii.gov/dbedt/info/energy/publications/). There is also a cloud effect in Hawaii. The study estimated that the cloud effect could cause an additional 10-15% reduction in DNI. However, due to fact that the SEGS Assessment was performed in 1992, it is not clear if current technologies would be able to ride out inter-hour cloud issues better than older technologies. Therefore, to obtain a Hawaii-specific range using the public sources vetted through the RETI stakeholder process, the top end of the range was assumed to represent Mojave Desert and adjusted by multiplying by 75% to account for the reduction in DNI. If assumed dry cooled 28% multiplied by 75% equals 21% and if wet cooled 32% multiplied by 75% is 24%. This represents the high end of the range as some cloud effect is likely. The low end assumes an additional 10% reduction due to clouds. If dry cooled, 28% multiplied by 65% is 18% and if wet cooled 32% multiplied by 65% is 21%. The full range is thus 18-24%. The pricing team modeled 19% and 21% conservatively in the scenarios.

In addition, the HECO pricing team used NREL's SAM model to validate the capacity factor assumptions for trough. Although SAM's CSP Reference Manual is currently only available in its draft version, this was used as a reference point to decide what default inputs to change in order to reflect a typical 2.5 MW installation in Hawaii. In the SAM model, the Parabolic Trough System was selected and the location was set to Honolulu, Hawaii. In the model's solar field options, the solar multiple was changed to 1.5 and the solar collector angle was set to -20 degrees (this negative angle tilts down the southern end of a solar array in the northern hemisphere). In the power block options, the Rated Turbine Net Capacity was set to 2.5 MW and the Design Turbine Gross Output was set to 2.75 MWe, 110% of the rated capacity. The "SAM/CSP Trough Power Cycles/Arizona Public Service ("APS") Ormat 1 MWe 300 C" power block was selected along with the respective "APS 1 MW Organic Rankine Cycle ("ORC") Wet" parasitic system. Lastly, the Thermal Energy Storage Hours was set to 0 in order to model a system without storage. The model comes preloaded with a collection of weather files including Honolulu's TMY2 information for latitude, longitude, local standard time, direct normal radiation, wind velocity, dry bulb temperature, dew point temperature and relative humidity derived from the 1961-1990 National Solar Radiation Data

Base ("NSRDB"). The technology assumptions made were also chosen to reflect a typical project for Hawaii's Tier 3. The chosen power block and parasitic system were within the 500 kW to 5 MW range for Hawaii's Tier 3 CSP projects. Using these modified inputs for the SAM model simulation gives an annual net electric output of 4,492 MWh which is equivalent to a 20.5% capacity factor. This capacity factor fell within the range of the calculation method from the public RETI process and provided confidence on the estimated range of capacity factors.

Dish capacity factors were estimated by Navigant Consulting to be between 22-30% in their Arizona roadmap efforts. Although they suggested typical capacity factors were at the low end of this range. More recently, dish manufacturers have emphasized that their technology's capacity factor at the top end of the range of conversion is in the 30-34% range. Dish technology efficiency is related to DNI, and thus the Hawaii specific numbers should be lower than in high insolation areas such as the Mojave Desert. Accordingly, a reduction between 25-35% is warranted using the same methodology used for the trough-based systems analysis. Thus, the capacity factor range for Hawaii was estimated to be between 20-23%. The scenarios modeled used 21% and 23%, respectively. A CPV specific study, "Opportunities and Challenges for Development of a Mature Concentrating Photovoltaic Power Industry", published by NREL in 2009 shows capacity factors at 23% in Los Angeles which has a similar insolation profile as Honolulu, Hawaii. The report can be found at the following link. (http://www.nrel.gov/pv/pdfs/43208.pdf) The DNI comparison chart is provided below for convenience.



On March 10, 2010, the Companies hosted a technical workshop with the parties and presented their assumptions for inputs to the model including capacity factor assumptions for the stakeholders to provide feedback. After the workshop, pricing team representatives had a conference call with representatives of a CSP developer to obtain their feedback on capacity factor assumptions. Subsequent to the call, the developer provided capacity factors for a trough facility sited at Kalaeloa, Hawaii, with a range of solar field ratios of 1:1 (18% capacity factor) and larger solar field with the same power system at 1.2:1 (21% capacity factor) and 1.5:1 (24% capacity factor). The developer also provided estimates for capital costs given the solar field ratio and the additional land required to oversize the field. The developer supplemented this information by providing the following table. While the numbers provided in the table have not been verified by a third-party, they do serve as a cross-reference for the calculated capacity factors from public sources.

Location	Schofield, HI	Kahuku, HI (average)	Kalaeloa, HI	
Annual DNI	1718	1888	2022	kWh/m2/yr
Daily DNI	4.7	5.17	5.5	kWh/m2/day
Project size	2.5	2.5	2.5	MW
Base Case	14.76	16.79	17.76	%
1.2 Multiplier	17.29	19.31	20.79	%
1.5 Multiplier	19.81	21.75	23.82	%

Scenario	CAPEX	Acres
Base Case	$6.08/watt	18.18
1.2 Multiplier	$6.52/watt	21.82
1.5 Multiplier	$7.12/watt	26.67

The Schofield location represents the low end of DNI levels on Oahu. Kahuku represents average DNI and Kalaeloa represents the higher end of DNI levels on Oahu. Developers of CSP projects should be targeting areas with average to high DNI, not areas with low DNI. Thus, the developer's capacity factor range (17%-24%) remains similar to the Companies' calculation for trough in Hawaii using public data sources and the Companies believe that the collaborative process has assisted in providing increased confidence in the assumptions made.

Capital Cost Assumptions

The pricing team completed an extensive search for publicly-available installed costs for CSP technology. The table below shows the results of the team's public costs analysis and represents the best publicly available numbers to its knowledge. The most recent work is the Black & Veatch analysis for the RETI in 2009, the NREL study conducted by Black & Veatch, the NREL study by Sargent & Lundy, and the Arizona roadmap report by Navigant. The reports can be found at the following links:

Black & Veatch Cost of Generation Analysis – RETI (2009):
http://www.energy.ca.gov/reti/steering/workgroups/phase2A_update/2009-11-19_meeting/RETI_Phase_2B_WG_Presentation_2009-11-19.pdf

The Arizona Roadmap report by Navigant:
(http://www.azcommerce.com/doclib/energy/az_solar_electric_roadmap_study_full_report.pdf)

NREL CSP Analysis – Black & Veatch (2006): http://www.nrel.gov/docs/fy06osti/39291.pdf
NREL CSP Analysis – Sargant & Lundy (2003): http://www.nrel.gov/csp/pdfs/35060.pdf

Dish	Type	Year	Capacity (kW)	Capital Cost ($/kW)	Note	Source
Stirling Energy System	Commercial	2008	25	9,000	Cost of single 25kw dish	News
Stirling Energy System	Commercial	2004	1,000	6,000	Cost of 25kW dishes for 1MW plant	CEC
Infinia	Commercial	2008	1,000	6,667	Cost of 3kW dishes for 1MW plant	News
Navigant Consulting	Estimate	2006	25	8,000	Estimate without scale up	Navigant Consulting
Trough	**Type**		**Capacity (kW)**	**Capital Cost ($/kW)**	**Note**	**Source**
Navigant Consulting	Estimate	2007	15,000	3,900	Estimate. No storage.	Navigant Consulting
Black & Veatch	Range	2008		3600-4700	B&V gives 3,600-4,700 cost/kw range	B&V Consulting
Black & Veatch- AZ roadmap	Estimate	2007	100,000	4,200	Wet-cooled solar trough plant	B&V Consulting
NREL- San Diego	Estimate	2005	100,000	3,246	Estimate for 2007	NREL
World Bank	Prototype	1999	13,800	4,490	Luz SEGS I In 1984	World Bank
World Bank	Prototype	1999	30,000	3,200-4,130	Luz SEGS II-VII built from 1984-1991	World Bank
World Bank	Estimate	1999	30,000	3,495	Est. 30MW for $3495 and 200MW for $2435	World Bank
APS Saguaro 1MW Plant	Commercial	2008	1,000	6,000	Saguaro plant with Organic Rankine	CH2MHill
CPV	**Type**		**Capacity (kW)**	**Capital Cost ($/kW)**	**Note**	**Source**
NREL	Range	2007		7000-8000	Tech roadmap gives 7,000-8,000 range	NREL
Navigant	Estimate	2006	15,000	5,000	Estimate	Navigant Consulting
SolFocus	Commercial	2009	92	6,040	Cost of 11 8.4kW for 92kW system	News
ORNL	Commercial	2007	150	6,500	Also has project breakdown	ORNL
Concentrix Solar	Commercial	2010	20,000	3,532	Paper on costs of FLATCON systems	Concentrix Solar

The Companies took the range of installed costs seen in mainland projects and added a Hawaii premium for labor and freight. The range of costs modeled from the mainland benchmarking is as follows: $6000/kW to $6667/kW for dish CSP systems, $5000/kW to $6500/kW for CPV CSP systems, and $4,700/kW to $6000/kW for trough CSP systems. In order to add the Hawaii premium, the pricing team made an assumption regarding the percent of total installed costs associated with equipment costs versus installation costs. An 80-20 breakout was assumed, so that 80% of the total installed costs were inflated by 9.72%

representing the 5% freight and 4.72% excise tax and 20% of the costs were inflated by 150% to represent the Hawaii labor premium. Thus the total installed modeled ranges from $5500 - $7850/kW including all three CSP technologies.

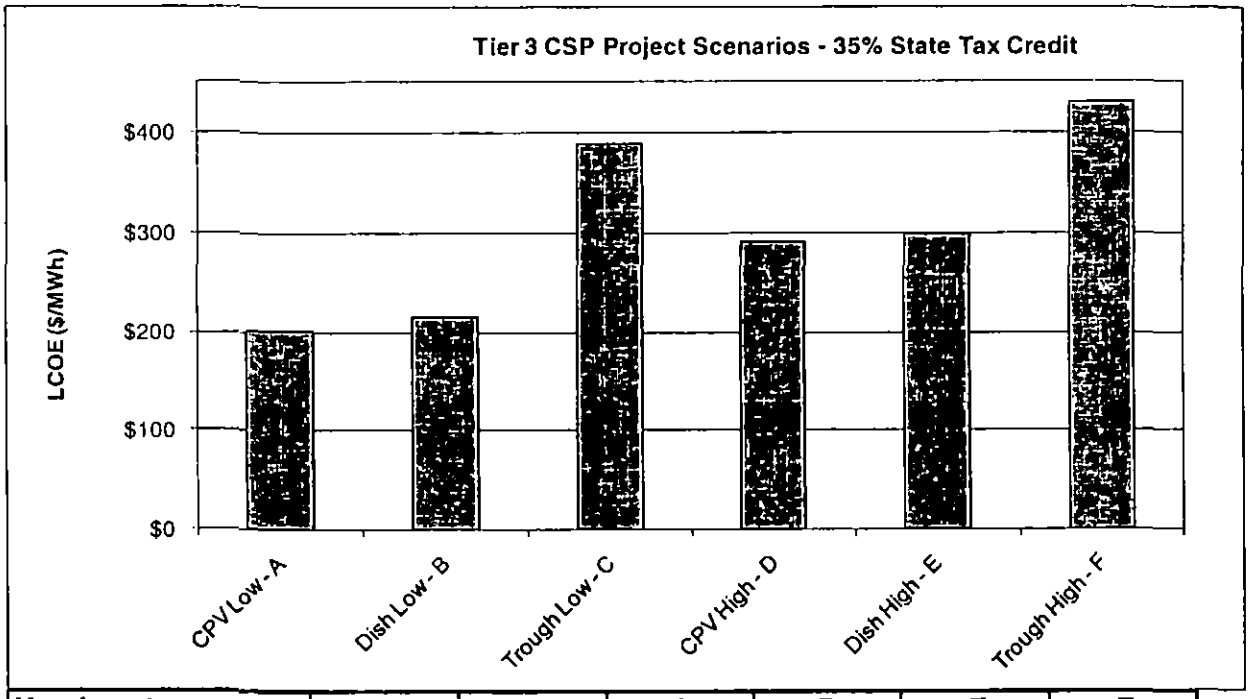
Interconnection and permitting were additional line items beyond the costs included in the adjusted total installed costs. Permitting costs are provided in a detailed memo by Planning Solutions (Attachment B). The CSP permitting cost estimates range from $35,000-$150,000. The estimate of $35,000 at the low end represents less than an acre of private land where the project does not require disturbance of high-value habitat and the site is served by existing roads. $90,000 was the medium estimate and represents the costs of an environmental assessment, permits from the Department of Health and Water Resources, some field work and no additional site construction permits. The high end of $150,000 involves greater than 1 acre of land disturbed for the site, preparation of a Chapter 343 application and some other additional assessments. To be conservative, the pricing team used the high end permitting costs for all the scenarios. This resulted in permitting costs that ranged from $30/kW to $150/kW. The Planning Solutions memo does not include the legal costs associated with securing permits. However, the transaction costs for project development (including legal fees) are assumed to be accounted for in the development costs included in the total installed cost estimates for all the technologies.

In addition to the permitting costs, the Companies also included interconnection cost assumptions as a separate line item. The interconnection cost assumptions are the same across technologies; depending on the project size they range between $255/kW-$530/kW. Insurance costs are assumed to be 0.6% of capital expenditures ("CapEx") per year. O&M costs were $50 for CPV, $60-$70 for trough and $80-$100 for dish. Land costs are assumed to be $10,000/acre per year. A 3% annual increase with the lease reset every 5 years was assumed. Dish is assumed to require 1acre for every 500 kW, CPV requires 2.5 acres per 500 kW, and trough requires 3-4 acres for every 500 kW depending on the solar field size. The trough scenario with the higher capacity factor assumed a higher capital cost and higher land costs assuming the solar field was oversized by a multiplier of 1.2 to 1.5.

Project Scenarios

The project scenarios for the three technologies (CPV, Dish and Trough) result in levelized costs which range from $202/MWh to $430/MWh assuming the 35% state tax credit is utilized. It is important to note that the three technologies are not all assumed to be able to fully monetize the state tax credit. As described in detail in the general benchmarking assumptions section, the CSP technologies are eligible for the state tax credit. However, the tax credit is capped at $500,000 per system. The state tax department has defined a system as a unit that "delivers usable electric energy." CPV systems can use additional inverters to create systems that deliver usable electric energy. Each dish contains a generator that produces usable electric energy. Accordingly, it is believed that those technologies will be

able to use multiple systems to fully monetize the state tax credit. However, trough systems heat a working fluid which is then used in a single generator. Thus, it appears unlikely, without a change in the wording of the current law, or relevant HDOT interpretation of the law, that multiple systems will be able to be claimed for trough projects. Consequently, at the present time trough projects will not be able to obtain the state tax credit based upon multiple systems. A graph of the scenarios modeled is included below. The impact of the different tax treatment for trough is evident.



Key Inputs	A	B	C	D	E	F
Size (kW)	5,000	5,000	5,000	1,000	1,000	1,000
Capacity Factor (%)	23%	23%	19%	22%	21%	21%
Installed Cost ($/kW)	$6,174	$7,352	$5,820	$8,365	$8,562	$7,777
LCOE	$202	$216	$389	$291	$299	$430

The levelized cost scenarios for CSP projects that utilize the 24.5% refundable tax credit range from $242/MWh to $430/MWh with a midpoint of $336/MWh. Due to the impact of the tax treatment, the pricing team also calculated the FIT rate based on the dish and CPV technologies alone. The FIT rate for dish and CPV alone would be $250/MWh with a 35% tax credit (thus the proposed rate represents a $66/MWh or a 6.6 cents per kWh premium). Alternatively, under a 24.5% tax credit the FIT rate would be $281/MWh (thus the proposed rate would provide a $55/MWh or 5.5 cents per kWh premium). This demonstrates that inclusion of trough into the benchmarking increases the resulting FIT pricing for all CSP technologies and could result in a significant premium to non-trough CSP technologies.

As discussed above, the Hawaiian Electric Companies believe that a 20-year debt term is appropriate and achievable for FIT projects in Hawaii. However, at the request of certain of the parties to the proceeding, the Companies have also run an illustrative 15-year debt term scenario in the event the Commission determines, based upon the record in this proceeding, that a 20-year debt term is not viable for a Hawaii FIT. If the project assumes a debt term of 15 years instead of 20 years, the FIT rate would be $331/MWh with a 35% state tax credit and $351/MWh with a 24.5% refundable state tax credit.

Proposed FIT Rate

The proposed FIT rate for CSP depends upon the state tax credit used. The Hawaiian Electric Companies propose a FIT rate of **$316/MWh** for projects that utilize the 35% state tax credit and **$336/MWh** for projects that utilize the 24.5% state tax credit. However, while the Companies view these rates as accurate given the current tax code, the disparate treatment of trough under the current law could lead to significant premiums in the form of profit margin for the other CSP technologies (Dish and CPV). The Companies also note that while the purpose of the FIT is to encourage a variety of renewable technologies, the significant price premium required for CSP above other technologies is cause for consideration of whether there should be an explicit limit to the number of megawatts of CSP allowed in the FIT program.

In-line Hydro Benchmarking

As discussed above, in their effort to benchmark in-line hydro projects, the Hawaiian Electric Companies experienced difficulty obtaining data points for these projects, particularly Hawaii-specific projects in the Tier 3 size range. Due to the limited data set, and lack of project development in the Tier 3 size range, the Commission may wish to consider deferring in-line hydropower projects eligibility for the Tier 3 Schedule FIT Tariff until at least the first FIT update. It is the Companies' understanding that there are a number of parties that are either in agreement with or would not object to this action by the Commission. If viable Tier 3 in-line hydro projects emerge during this time period they would be able to access the baseline FIT rate or avail themselves of other procurement methods such as bilateral contracting with the utility. To the extent the Commission determines that it is appropriate to include Tier 3 in-line hydro projects in the FIT at this time, the following provides a cost of generation analysis based upon the data available.

Capacity Factor Assumptions

The capacity factor range is taken from KEMA's 2009 CEC COGS, which specifically analyzed the range of capacity factors and installed cost of in-conduit (or in-line) hydro generation. The project sizes analyzed in the KEMA study were from 100kW to 3MW. The capacity factor range quoted in the study was 10%-90%. The pricing team used the common

assumption of a 50% capacity factor for all the in-line hydro scenarios modeled. The KEMA 2009 CEC COGS can be found at the following link: (http://www.energy.ca.gov/2009_energypolicy/documents/2009-08-25_workshop/presentations/05_KEMA_Building_and_Community_Scale_Renewable_Technology_Costs.PDF).

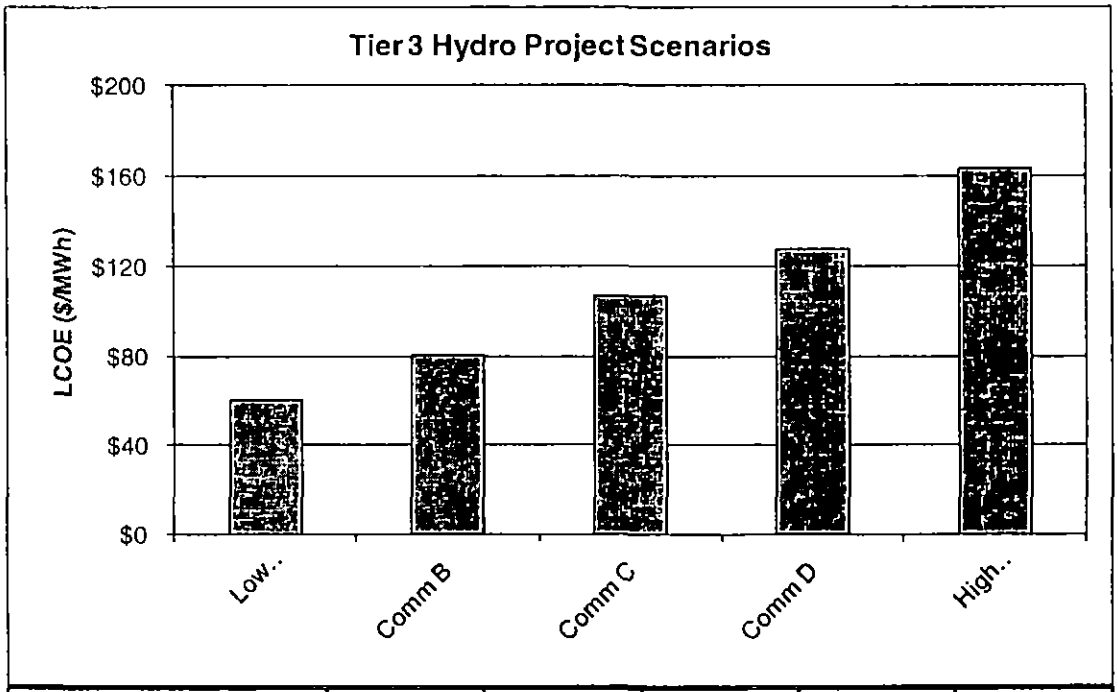
Capital Cost Assumptions

The capital cost assumptions are also taken from KEMA's 2009 CEC COGS (link above). The KEMA study presented a capital cost range from $1,156/kW-$3,853/kW. These costs were inflated to include Hawaii specific freight & excise tax and Hawaii specific labor and materials costs. The cost range including the Hawaii premium is $1385/kW to $4616/kW. In addition, the Companies added Hawaii specific permitting and interconnection costs. Permitting costs are provided in the detailed Pricing Solutions memo attached as Attachment B. The in-line hydro permitting cost estimates range from $2,500-$30,000. These permitting costs are lower than those for the other technologies due to the definition of in-line hydro as "utilizing an existing pipe." The low end of the cost range is representative of the costs to file the paperwork and make a conceptual plan. The mid range cost of $15,000 represents the cost of obtaining a departmental permit that is exempt from Chapter 343. The high end permitting cost of $30,000 represents a Chapter 343 environmental assessment but no extensive biological or cultural impact surveys. The pricing team assumed the high end permitting cost in its analysis which led to a range of $10/kW-$60/kW depending on project size. In addition to the permitting costs, the pricing team also included interconnection cost assumptions as a separate line item. The interconnection cost assumptions are the same across technologies; depending on the project size they range between $255/kW-$530/kW. The total installed capital cost range is $1640 to $5195/kW including the Hawaii premiums and Hawaii specific interconnection and permitting costs.

In addition, the pricing team reviewed the operating cost range in the KEMA CEC COGS (link above) which was $12/kW-yr to $105/kW-yr (represented as a consolidated O&M cost). The pricing team utilized the middle of the range as the common assumption for all the in-line hydro project scenarios, $60/kW-yr.

Project Scenarios

The project scenarios for in-line hydro result in levelized costs which range from $60/MWh to $162/MWh. A graph showing the 5 project scenarios modeled is shown below. The midpoint of the range is $111/MWh.



Key Inputs	A	B	C	D	E
Size (kW)	2,500	2,500	1,000	1,000	500
Capacity Factor (%)	50%	50%	50%	50%	50%
Installed Cost ($/kW)	$ 1,687	$ 2,494	$ 3,560	$ 4,368	$ 5,736
O&M ($/kW-yr)	$60	$60	$60	$60	$60

The pricing team has run an illustrative 15 year debt term scenario in case the Commission determines that 20-year debt is not viable even under a FIT program as is the documented HECO assumption and supported in the general benchmarking section. If the project assumes a debt term of 15 years instead of 20 years, the FIT rate would be $115/MWh.

Proposed FIT Rate

If the Commission chooses to retain in-line hydro as an eligible Tier 3 technology, the proposed Tier 3 in-line hydro FIT rate is $111/MWh.[11]

[11] The Tier 1 and 2 FIT rates for in-line hydro projects submitted by the Hawaiian Electric Companies in their January 7, 2010 filing assumed a 5-year MACRS depreciation to be consistent with the depreciation treatment for the other eligible FIT technologies. Upon further analysis, the Companies have concluded that 20-year MACRS depreciation is more appropriate for inline hydro projects. The difficulty in determining the depreciation treatment for this technology is that it is not specifically named as one of the eligible renewable energy technologies that qualifies for 5-year MACRS depreciation under the federal tax code 26 USC § 168(e)(3)(B)(vi). In the absence of a specific asset class for inline hydro, the Companies are relying on the activity class which best fits inline hydro, which is Asset class 49.11 - electric utility hydraulic production plant. This type of plant has a depreciation recovery period of 20 years. With a 20-year depreciation schedule (150% declining balance), the recalculated Tiers 1 and 2 inline hydro FIT prices would be as follows: Tier 1:

In charging the Hawaiian Electric Companies with the responsibility for developing the initial FIT rates, the Commission noted that the utilities "already possess information about the rates for existing PPAs and accepted competitive bids" and, in addition, "having negotiated existing PPAs, the utility should be familiar with typical interconnection and IRS costs." (Decision and Order at 84) The Commission clarified that in evaluating the "justness and reasonableness of proposed FIT rates, the commission will look most favorably on those based on Hawaii-specific cost and performance data, followed by mainland cost and performance data. The commission encourages the use of existing Hawaii PPAs and accepted competitive bids to evaluate the reasonableness of cost-based rates." (Id.) As discussed in detail above, the proposed Tier 3 FIT rates were determined based upon a rigorous examination of Hawaii-specific cost and performance data where available, followed by mainland cost and performance data. Additionally, and without disclosing information which may be deemed confidential or proprietary, the Hawaiian Electric Companies have examined both existing PPAs and accepted competitive bids and determined that the cost-based rates proposed herein are not inconsistent with PV rates contained in existing agreements and proposals.

Baseline FIT Rate

Section H of the Schedule FIT Tariff provides for a baseline FIT rate for certain RPS eligible technologies which are not otherwise eligible for a specific FIT energy payment rate. The baseline FIT rate will be the lowest specified FIT energy payment rate for any project size or technology on any island and accordingly, will likely have to be developed once the pricing for Tier 3 projects has been approved by the Commission. Additionally, projects using the baseline FIT Rate cannot exceed the maximum size limits for Schedule FIT projects on the island that the project is proposed. This is consistent with the provision for a baseline FIT rate contained in the Decision and Order at 36.

It is the Hawaiian Electric Companies' understanding of the Commission's directives regarding establishment of a baseline rate that the Commission intended there to be a single baseline rate. As the Commission stated, "[i]n this way, if a technology is inexpensive enough to utilize the baseline rate, and it otherwise complies with the requirements set forth in the FIT tariff, it should be included in the FIT as it would provide a benefit to the State." (Decision and Order at 37) (Emphasis supplied) Certain of the parties to this proceeding have interpreted the Commission's directives to indicate that the Commission intended that there be multiple baseline rates depending in part on the number of unique tiers adopted by the Commission. If this is the Commission's intention then the appropriate baseline rates can be

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$255/Mwh; Tier 2: $227/Mwh. These revised prices are $42/Mwh and $38/Mwh higher than those submitted in the original Tiers 1 and 2 tariff filing, respectively.

determined based upon an examination of the Tier 1, Tier 2 and Tier 3 FIT Tariff rates which are ultimately approved by the Commission.

Term

At page 85 of the Decision and Order, the Commission adopted a FIT contract term of 20 years. Section I of the Schedule FIT Tariff provides for a 20-year Agreement term and is consistent with the Commission's directive.

Electric Energy Delivered to the Seller by the Company

Section J of the Tier 3 Schedule FIT Tariff simply clarifies that any electric energy delivered to the Seller by the Company shall be billed under the Company's applicable rate schedule.

Allowed Project Development Timeframe, Fees and Deposits

At pages 92-93 of the Commission's Decision and Order the Commission stated that the queuing and interconnection procedures to be developed by the Company in conjunction with the Independent Observer "*should include project development milestones to advance in the queue and deposits for applicants.*" According to the Commission, such procedures *should* "maintain the incentive for only viable projects to apply for interconnection studies." (Id.) Moreover, the Commission has directed that "to deter frivolous projects from filling the caps, a significant application fee should be required." (Decision and Order at 58)

Consistent with this determination, the Schedule FIT Tariff (at Sections K and L) includes references to a project development timeframe, the payment of an application fee (to deter frivolous applications), reservation fee (to incent project completion), security deposit(s) (to promote timely development), and the potential forfeiture of certain fees and security deposits to the extent a developer fails to meet the allowed project development timeframe. The fees and deposits set forth in the Tier 3 Schedule FIT Tariff have been developed and evaluated in consultation with the Independent Observer in this proceeding consistent with the Commission's directives that the Independent Observer participate in and oversee administration of the queuing process. (Decision and Order at 93)

Section L of the Schedule FIT Tariff also contains provision for a nominal monthly service charge to be paid for the metering, billing and administration of the Seller's purchased power under the Schedule FIT Agreement. This section is self-explanatory and intended to provide some compensation to the utility and its ratepayers for the costs associated with administering the Seller's Agreement.

Participation in other Company Programs:

Section M addresses the circumstance where a Seller may have multiple generators on a particular site. To avoid duplicative compensation, the section requires that multiple generators may not participate in any other Company interruptible or net energy metering programs unless the multiple generators can be segregated electrically from each other.

IV. Tier 3 Schedule FIT Agreement

At page 87, of the Decision and Order, the Commission states that "to the extent possible, the utility should provide standard offer contracts with commission-approved FIT rates and mandated terms and conditions." The Commission goes on to state that "[e]xcept where the commission has dictated specific terms and conditions, the terms and conditions of the standard offer contracts should, to the extent possible, closely match those of existing negotiated PPAs."

The Tier 3 Schedule FIT Agreement attached to the Tier 3 Schedule FIT Tariff does, to the extent possible, include terms and conditions which match those of existing negotiated PPAs. Where the Tier 3 Schedule FIT Agreement differs, it does so in large part to reflect specific directives in the Commission's Decision and Order, or to standardize those terms which appear in the Companies' existing PPAs. The Schedule FIT Agreement for Tiers 1 and 2 attempted to simplify the applicable terms and conditions to the extent possible in consideration of the proposed project sizes. As the Commission has recognized, Tier 3 is "for projects that are in many cases not behind-the-meter and are designed to export large amounts of electricity to the grid." (Decision and Order at 46) Accordingly, the Tier 3 Schedule FIT Agreement incorporates terms and conditions appropriate for projects of this size and helps ensure both that the utility has the appropriate tools necessary to manage these larger scale resources which in the aggregate could account for a significant portion of the non-utility generation on the utilities' grids, and that all parties to the Tier 3 Schedule FIT Agreement are able to meet their obligations under the Agreement for the entire term of the Agreement pursuant to the Commission's Decision and Order. The following briefly discusses the specific areas of compliance between the Tier 3 Schedule FIT Agreement and the Decision and Order.

A principal directive in the Commission's Decision and Order is the Companies' obligation to ensure system reliability. In particular, the Decision and Order expressly states that "*the HECO Companies maintain the ability and obligation to refuse to interconnect projects that will substantially compromise reliability or result in an unreasonable cost to ratepayers.*" (Decision and Order at 44). Consistent with this, the Decision and Order observes that based upon the reliability standards to be developed by the Company "*the utility could determine that projects above certain sizes or using certain technologies are not possible in certain locations without degrading reliability or necessitating costly system*

upgrades. As discussed below, the utility need not interconnect projects that would likely face significant curtailment or cause significant curtailment for existing renewable energy generators." (Id.)

Article 1 (Parallel Operation), Article 3 (Facility Owner And/Or Operated By Seller), Article 5 (Scheduling), Article 6 (Forecasting), Article 8 (Continuity of Service), Article 9 (Personnel and System Safety), Article 25 (Good Engineering And Operating Practices), and the relevant Attachments applicable to those Articles, collectively address maintaining the Company's ability to ensure that it can meet the obligation described in the Decision and Order. With regard to Article 8 and the issue of curtailment, the Commission has recognized that "[a]s isolated island grids, the HECO Companies' systems have no export outlet for excess energy, and, as such, where conditions with excess energy begin to develop, curtailment is required." (Decision and Order at 70)

Based upon the Commission's directive that "the terms and conditions of the standard offer contracts should, to the extent possible, closely match those of existing negotiated PPAs" (Decision and Order at 87), the Companies have proposed a curtailment methodology similar to what is contained in the Companies' existing PPAs. In general, when the Companies determine that curtailment of energy becomes necessary for reasons other than those directly attributable to a Facility, curtailments are made to the extent possible in reverse chronological order of the chronological seniority dates determined by Company for the contracts, with deliveries under the contract with the most recent chronological seniority date being the first curtailed, and deliveries under the contract with the earliest chronological seniority date being the last curtailed. In these circumstances, the chronological seniority date is generally the PUC Approval Order Date of the Non-appealable PUC Approval Order.

Because the Commission has determined that there "is no legal or practical need for the commission to review and approve" the Schedule FIT Agreement (to the extent the Commission has approved the standard contract, and if the contract between the parties conforms to the standard contract, and if the quantity and price terms are consistent with the commission-approved quantity cap and prices)(Decision and Order at 87) Schedule FIT Agreements will not have a PUC Approval Order Date. Accordingly, the Tier 3 Schedule FIT Agreement provides that FIT facilities shall be grouped together in one or more blocks where each block consists of all curtailable facilities that applied for the Schedule FIT in the same Schedule FIT release phase ("Schedule FIT Phase"). Each FIT block will be assigned a date corresponding to the date on which the particular Schedule FIT Phase was made available to the public for applications ("FIT Block Release Date"). The chronological seniority date with respect to the Schedule FIT Agreements shall be the FIT Block Release Date. (See, Tier 3 Schedule FIT Agreement at Attachment B (Facility Owned by Seller), Section 2(F)(iv)).

As discussed above, availability of the Tier 3 Schedule FIT Tariff should ultimately be dependent upon a Commission determination for each island system that allowing Tier 3

projects to go forward would not be in conflict with the Commission's reliability and cost directives set forth in detail herein. The curtailment methodology described above was developed for the Oahu system based upon the system studies and evaluations which preliminarily indicate that no significant system wide reliability or curtailment issues are expected for implementation of the initial 60 MW FIT program on Oahu. Consistent with the determinations in the Companies' Report on Reliability Standards that there is limited room at this time to accommodate additional renewable resources without significant curtailment of either existing or planned renewable resources, utility specific curtailment methodologies which account for the unique operational issues and constraints on each island system remain to be developed for Maui and the Island of Hawaii. As discussed in the Companies' February 26, 2010 response to the Commission's request for more information on the Companies' proposal to convene a Reliability Standards Working Group, the Companies have proposed that implementation of FIT on the HELCO and MECO systems should be subject to review by the proposed Working Group.[12]

At pages 89 and 90 of the Decision and Order, the Commission adopts certain annual reporting requirements for renewable project developers. Article 29 of the Tier 3 Schedule FIT Agreement (Regulatory Compliance) incorporates the Commission's order into the Agreement.

Finally, at pages 90-91 of the Decision and Order, the Commission provides some direction on the FIT project's responsibility at the conclusion of the FIT term. Specifically, projects must offer to sell their electricity to the utility on an annual basis. Section 12.2 of Article 12 (Term of Agreement and Company's Option to Purchase at End of Term) of the Tier 3 Schedule FIT Agreement addresses this requirement.

The Hawaiian Electric Companies remain firmly committed to move decisively away from imported fossil fuel for electricity generation and towards indigenously produced renewable energy. The Companies' proposed FIT Program, inclusive of this submission for

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[12] As stated in the Hawaiian Electric Companies' January 7, 2010 correspondence transmitting their proposed Tariff and Agreement for Schedule FIT Tiers 1 and 2, "because the issue of curtailment methodology would be particularly relevant to Tier 3 project sizes and will likely be addressed during that phase of the proceeding, the Tier 1 and Tier 2 Schedule FIT Agreement contains a placeholder which can be completed upon any approval by the Commission of an appropriate curtailment order methodology in that phase of the proceeding." (January 7, 2010 correspondence at 14) Accordingly, to the extent that the Commission approves the foregoing curtailment methodology for the Tier 3 Schedule FIT Agreement (for Oahu), the Hawaiian Electric Companies respectfully request that the Commission authorize the Companies to utilize that curtailment methodology for Schedule FIT Tier 1 and Tier 2 Agreements to the extent that excess energy curtailment may be applicable (to those facilities which have a Design Capacity above the trigger for Supervisory Control and Data Acquisition ("SCADA") set forth in the Company Tariff, Rule 14, Section H, or the Company, in its sole discretion, has deemed that an alternate means of curtailment is technically feasible for such Facility.

Tier 3 level projects, will accelerate the addition of renewable energy from new sources and complements a host of other renewable resource procurement programs in existence and to be developed by the Companies to facilitate movement toward a renewable energy future for the State. The Companies look forward to implementation of the FIT Program on Oahu as soon as possible and to the integration of increased levels of renewable resources on the other island systems in accordance with the Commission's directives in this proceeding.

The Hawaiian Electric Companies respectfully submit that the foregoing Schedule FIT Tier 3 Tariffs and Schedule FIT Agreement are reasonable, compliant with the directives set forth in the Commission's Decision and Order and will serve to incent new, renewable energy generation in the Companies' service territories. The Hawaiian Electric Companies therefore respectfully request Commission approval of these documents as the Commission may deem appropriate under the circumstances

The Hawaiian Electric Companies stand ready to provide any additional information which the Commission may require in its efforts to evaluate and approve the proposed Tier 3 FIT Program documents.

Sincerely,

Darcy L. Endo-Omoto
Vice President
Hawaiian Electric Company, Inc.
Hawaii Electric Light Company, Inc.
Maui Electric Company, Limited

Attachments:

c: Service List

Prevailing Wind Power Price Quote

WES Standard Pricing Estimates

	WES18	WES30
Size (kW)	**80**	**250**
Equipment Installation		
Turbine, Tower, Relay	260,000	590,000
Freight	12,150	21,263
Installation	115,000	255,000
Subtotal Equip & Install	387,150	866,263
Fees		
Stuctural Engineer	8,000	15,000
Permit Fee *	6,000	9,000
Permit Processing	8,000	8,000
Subtotal Fees	22,000	32,000
Total Installed Price	409,150	898,263
Application Processing (Optional)		
Utility	8,000	8,000
Subtotal Processing	8,000	8,000
Gross PWP Charges	417,150	906,263
Rebate **	-128,000	269,479
Net cash outlay	289,150	1,175,741
Est'd Annual Production: Mwh's per year @ 13 mph avg	160	460

Projected Life Span:	20 Years

PLANNING SOLUTIONS

TO: Mary Ellen Nordyke-Grace, (maryellen.nordykegrace@heco.com)
FROM: Perry White
DATE: February 24, 2010
SUBJECT: Feed-in Tariff Tier 3 Pricing Development: Permitting and Environmental Factors

Introduction

In accordance with your request, Planning Solutions Inc. (PSI) has reviewed the spreadsheets that Energy and Environmental Economics, Inc. (E3) has developed for the purpose of identifying a means of incorporating likely environmental impact assessment and permitting costs into the proposed methodology for FIT Tier 3 pricing for onshore wind, in-line hydro, PV, and concentrated solar. This memorandum presents our preliminary recommendations. It is our understanding that HECO will use this information in relationship to develop an additional line item under the "Other Cost" category in the pricing model.

Based on the information that HECO provided, PSI considered the four different Size/Technology combinations shown in Table 1.

Table 1. Size/Technology Combinations Considered

Technology	*Island*	*Sizes*	
		Minimum	*Maximum*
PV	O'ahu	500 kW	5 MW
	Maui	250 kW	2.72 MW
	Moloka'i	100 kW	100 kW
	Lana'i	100 kW	100 kW
	Hawai'i	250 kW	2.72 MW
CSP	O'ahu	500 kW	5 MW
	Maui	250 kW	2.72 MW
	Moloka'i	100 kW	100 kW
	Lana'i	100 kW	100 kW
	Hawai'i	250 kW	2.72 MW
In-Line Hydropower	O'ahu	500 kW	5 MW
	Maui	250 kW	2.72 MW
	Moloka'i	100 kW	100 kW
	Lana'i	100 kW	100 kW
	Hawai'i	250 kW	2.72 MW
Onshore Wind	O'ahu	500 kW	5 MW
	Maui	250 kW	2.72 MW
	Moloka'i	100 kW	100 kW
	Lana'i	100 kW	100 kW
	Hawai'i	250 kW	2.72 MW

Factors Affecting the Cost of Obtaining Land Use Approvals

Number of Approvals Needed. Unlike many of the factors that are evaluated in the pricing scenarios, a project's location relative to existing land use, zoning, and environmental features is often much more significant than is its size in determining the cost of obtaining land use permits and environmental approvals.

Table 2 lists some of the permits and approvals that could be needed from the State of Hawai'i for each of the four technologies; it also provides a qualitative estimate of the likelihood that a typical project of that sort would require the approval. Table 3 provides the same kind of information for possible County approvals (using Maui County as an example). Finally, Table 4 provides a comparable listing for Federal permits and approvals. In all of the tables:

- Cells with gray fill indicate that there is either no or very little likelihood of the approval being required.
- Where there is a chance that the approval could be required, the likelihood of its being needed is indicated by an "L" (low), "M" (Moderate), or "H" (High).

The tables illustrates two important points.

(1) One of the technologies, In-Line Hydro, has little likelihood of having high permitting costs regardless of its location. This stems from the fact that installation of the generating equipment requires access, but very little ground disturbance, no substantial new external structures, and a likelihood that even the power takeoff points would be in locations that are accessible without substantial new road or transmission line construction.

(2) There is a large range of possibilities for all of the other technologies. Harkening back to the point made in the first paragraph of this section, this implies that economies of scale will tend to make the "per megawatt" cost of obtaining land use and environmental approvals substantially lower for projects towards the upper end of the size range than it is for projects at the lower end.

Complexity/Difficulty of Obtaining Approvals. While the number of approvals needed is important in and of itself, it is only part of the story. Sometimes projects that require only a single discretionary approval can prove inordinately difficult to permit because they involve an exceptionally sensitive resource, have one or more neighbors who strenuously oppose it, or raise questions that are challenging to address to the satisfaction of approving authorities.

Approach to Estimating Cost for Permitting

Because of the huge variability in the permitting requirements for individual projects depending upon the specific circumstances of their location relative to land use zoning, natural resource management areas, special management areas, and the like, it was not possible develop a precise formula for estimating costs. Instead, we relied upon professional experience with projects we judged to have similar permitting and approval requirements.

Table 2. Example State of Hawai'i Approvals Required for Tier 3 Projects.

Agency	*Approval*	*Probability of Requiring Approval*			
		PV	*CSP*	*In-Line Hydro*	*Onshore Wind*
Dept. of Health	SEC 401 Water Quality	[redacted]	L	[redacted]	
	NPDES	[redacted]	L	[redacted]	H
	Zone of Mixing Permit	[redacted]	[redacted]	[redacted]	[redacted]
	Health Risk Assessment	[redacted]	[redacted]	[redacted]	[redacted]
	Superfund Amendment & Reauthorization Act (SARA) Reporting	L	L	[redacted]	L
	Noise Permit	L	M	[redacted]	M
Dept. of Land and Natural Resources - Division of Forestry and Wildlife	Incidental Take License & Habitat Conservation Plan	L	L	[redacted]	H
Office of Planning	CZM Federal Consistency	L	L	[redacted]	L
Land Use Commission	Special Use Permit - over 15 acres	L	L	[redacted]	L
	District Boundary amendment	[redacted]	[redacted]	[redacted]	[redacted]
Dept. of Land and Natural Resources	Right-of-Entry/Revocable Permit	M	M	[redacted]	H
	Easement or lease for use of State Land	M	M	L	H
	Chapter 343 Environmental Impact Statement Approval	M	M	[redacted]	H
	Stream Channel Alteration Permit	[redacted]	[redacted]	[redacted]	L
	Historic Sites Review (Section 6E)	M	M	[redacted]	H
	Wildlife Sanctuary Entry	[redacted]	[redacted]	[redacted]	M
	Closed Watershed Entry	[redacted]	[redacted]	L	L
	Natural Area Reserves Permit	[redacted]	[redacted]	[redacted]	[redacted]
Dept. of Transportation	Airport Clear Zone Area Construction	[redacted]	[redacted]	[redacted]	M
	Overloads approval	L	M	[redacted]	H
Public Utilities Commission	Transmission Line Approval	L	M	[redacted]	M-H

Table 3. County Approvals for Tier 3 Projects (Maui Example).

Agency	*Approval*	*Probability of Requiring Approval*			
		PV	*CSP*	*In-Line Hydro*	*On-shore Wind*
Dept. of Environmental Mgt. - Wastewater Div.	Wastewater Discharge Permit		L		
Dept. of Fire & Public Safety	Temporary Structure Permit				
Planning Dept.	Change in Zoning Permit				
Planning Dept.	Shoreline Setback Variance				
Planning Dept.	Special Use Permit (- Land Use Comm.	L	M		L
Planning Dept - Current Planning Division	Special Management Area Use Permit (SMX,SM1-SM7)				
	District Boundary Amendment (DBA) - State Land Use Commission				
	Planned Development Approval				
	Project District Development Approval				
	Project Master Plan Preview				
	Special Accessory Use Permit	L	L		
	Special Use Permit - Land Use Comm.		L		
	County Special Use Permit	L	L		
Planning Department - Zoning Administration and Enforcement Division	Board of Variance & Appeals				
	Zoning and Flood Confirmation Form	L	L	L	L
	Flood Development Permit				L
Maui County	Community Plan Amendment				
	Conditional Use Permit (CP)				
Public Works Dept - Development Services Admin	Building Permit	L	L		H
	Electrical Permit	L	L		H
	Moving Permit	L	L		L

Table 4. Federal Approvals for Tier 3 Projects

Agency	*Approval*	*Probability of Requiring Approval*			
		PV	*CSP*	*In-Line Hydro*	*On-shore Wind*
Dept. of Agriculture (DOA)	Prime Farmland - DOA/SCS		L		L
Army Corps of Engineers	Clean Water Act Section 404 Permit for Discharges of Dredged or Fill Materials into Waters of the U.S.		L		L
	Rivers and Harbors Act Section 9, 10 Permit for Structures or Work in or Affecting Navigable Waters of the U.S.		L		L
Fish and Wildlife Service	Incidental Take Permit (endangered Species)				H
National Park Service	Visibility Analysis				L-M

Table 5 provides "low", "middle", and "high" figures for obtaining permits and land use approvals. Readers should keep in mind, however, that the numbers do not really represent extremes or averages. The "high" values, for example, are not the highest possible; rather they are estimates of what the costs might be in a situation where one night reasonably decide to move forward if one knew from the outset that these were the costs one would experience. Neither are the "middle" values "averages" or even ones that it would be appropriate to assume would be encountered in most cases; rather they are amounts that one might use for initial decision-making with respect to the likely viability of a project. The important assumptions and qualifications applicable to the estimates are summarized in the following sections.

Table 5. Summary of Permitting and Environmental Cost Estimates by Technology.

	In-Line Hydro	*PV*	*CSP*	*On-shore Wind*
Low	$2,500	$10,000	$35,000	$15,000
Middle	$15,000	$30,000	$90,000	$100,000
High	$30,000	$75,000	$150,000	$500,000

Cost for Permitting and Environmental Factors – **In-Line Hydro Projects**

Low. The "low" estimate for this technology ($2,500) provides only for: (i) assembling a conceptual plan, (ii) checking (in person or by telephone) with the Planning Department of the island on which the project would be constructed to make sure that permits are not needed, and (iii) writing a letter confirming that no approvals will be needed.

Medium. The "medium" cost estimate ($15,000) assumes that a project is in the State Conservation District but can be completed with a Departmental (rather than a Board) permit and is exempt from the requirement for a Chapter 343 environmental assessment or EIS.

High. The "high" estimate for this technology ($30,000) assumes that a Chapter 343 environmental assessment and Conservation District Use Permit will be needed from the Board of Land and Natural Resources. However, it also assumes that work that no extensive earthmoving or other heavy construction work that could trigger the need for extensive biological or cultural impact surveys would be needed.

Cost for Permitting and Environmental Factors – **PV Projects**

Low. The "low" estimate for this technology ($10,000) assumes that the project:

- requires the disturbance of less than an acre of land,
- is on private property,
- is on land that is in the State Urban, Rural, or Agricultural District,
- is not in an area that requires the disturbance of high-value habitat, and
- is served by existing access roads and transmission facilities.

It is, of course, possible that PV facilities at the smaller end of this size range can be placed on existing structures. If this is the case, and assuming that the structural analysis is done as part of the regular building design and the permits are processed in conjunction with the remainder of the structure, it is possible that no "extra" costs would be incurred for such a project.

Medium. The "medium" cost estimate ($30,000) assumes that an environmental assessment will be needed because of location or funding connections, but that no substantial land disturbance will be involved, a cultural impact assessment will not be needed, and the construction work will not entail noise or traffic that could require special studies.

High. The "high" estimate for this technology ($75,000) assumes that the project will require the disturbance of more than an acre of land (and will, therefore, require filing an NOI-C with the State Department of Health). It also assumes that it will use public land and/or involve some other action that will require the preparation of a Chapter 343 Environmental Assessment. Because of the relatively limited construction that is associated with this technology, the cost estimate assumes that only a moderate amount of other work will be needed.

Cost for Permitting and Environmental Factors – **CSP Projects**

Low. The "low" estimate for this technology ($35,000) assumes that the project:

- requires the disturbance of less than an acre of land,
- is on private property,
- is on land that is in the State Urban, Rural, or Agricultural District,
- is not in an area that requires the disturbance of high-value habitat, and
- is served by existing access roads and transmission facilities.

It further assumes that an environmental assessment will be needed but that no substantial land disturbance will be involved, a cultural impact assessment will not be needed, and that the construction work will not entail noise or traffic that could require special studies.

Medium. The "medium" cost estimate ($90,000) assumes that an environmental assessment will be needed and that the use of wells and other "special-built" water-supply/wastewater disposal facilities will require permits from the Department of Health and/or the Commission on Water Resource Management. It also

provides for a modest amount of environmental field work, but assumes that no special noise or traffic issues will arise that could require special studies.

High. The "high" estimate for this technology ($150,000) assumes that the project will require the disturbance of more than an acre of land (and will, therefore, require filing an NOI-C with the State Department of Health). It also assumes that it will use public land and/or involve some other action that will require the preparation of a Chapter 343 Environmental Assessment. Because of the relatively limited construction that is associated with this technology, the cost estimate assumes that only a moderate amount of other work will be needed.

***Cost for Permitting and Environmental Factors* – On-Shore Wind Projects**

Low. The "low" estimate for this technology ($15,000) assumes that the project is at the low end of the project range and:

- requires the disturbance of less than an acre of land,
- is on private property,
- is on land that is in the State Urban, Rural, or Agricultural District,
- is not in an area that requires the disturbance of high-value habitat, and
- is served by existing access roads and transmission facilities.

It further assumes that an environmental assessment will not be needed and that no substantial land disturbance will be involved, a cultural impact assessment will not be needed, and that the construction work will not entail noise or traffic that could require special studies.

Medium. The "medium" cost estimate ($100,000) assumes that an environmental assessment will be needed and that the use of wells and other "special-built" water-supply/wastewater disposal facilities will require permits from the Department of Health and/or the Commission on Water Resource Management. It also provides for a modest amount of environmental field work, but assumes that no special noise or traffic issues will arise that could require special studies.

High. The "high" estimate for this technology ($500,000) assumes that the project will require the full gamut of permits. Perhaps more importantly, it assumes it will require preparation of a Habitat Conservation Plan and issuance of an Incidental Take Permit (from the US Fish and Wildlife Service) and Incidental Take License (from the State of Hawai'i Board of Land and Natural Resources) because of effects on endangered species. It also assumes disturbance of more than an acre of land (and, therefore, filing an NOI-C with the State Department of Health). It also assumes that it will use public land and/or involve some other action that will require the preparation of a Chapter 343 Environmental Assessment.

SCHEDULE FIT TARIFF
TIER 3

OAHU

SCHEDULE FIT TIER 3
HAWAIIAN ELECTRIC COMPANY, INC. ("COMPANY")

Feed-In Tariff - Purchases from Tier 3 Eligible Renewable Energy Generating Facilities

A. Availability:

This schedule feed-in tariff ("FIT") for Tier 3 Eligible Renewable Energy Generating Facilities ("Schedule FIT") is available to customers, individuals, and independent power producers ("Sellers") who wish to sell to the Company electric energy from a Facility (as defined in Section B, below). This Schedule FIT sets forth the program eligibility, rates, and the terms and conditions for the sale of electric energy to the Company under this Schedule FIT.

B. Eligibility:

(1) An eligible renewable energy generating facility under this Schedule FIT is an electric energy generating facility which meets the following criteria ("Facility"):

(a) Sells electric energy to the Company; and

(b) With respect to Tier 3 Facilities, is a new:

(i) Photovoltaic ("PV") system with a Design Capacity (defined as the capacity of the generator in kilowatts ("kW") as established by the manufacturer that is available for use at the Facility to meet customer load and/or exported to the Company system for sale to the Company under Schedule FIT) (alternating current or "AC") greater than 500kW and up to and including the lesser of 5 MW (5,000 kW) or 1% of the system peak load; or

(ii) Concentrated Solar Power ("CSP") system with a Design Capacity (AC) greater than 500 kW and up to and including the lesser of 5 MW (5,000 kW) or 1% of the system peak load; or

(iii) Onshore wind system with a Design Capacity (AC) greater than 100 kW and up to and including the lesser of 5 MW (5,000 kW) or 1% of the system peak load.

(iv) In-line hydropower system with a Design Capacity (AC) greater than 100 kW and up to and including the lesser of 5 MW (5,000 kW) or 1% of the system peak load. [Provisional – If Included]

(c) For purposes of this Schedule FIT, the following definitions shall apply:

(i) CSP is defined as a Facility that uses mirrors or lenses to concentrate the sun's heat in order to generate electricity.

(ii) In-line hydropower is defined as a hydroelectric Facility that utilizes energy from a water pipeline system that is designed primarily to serve another functional purpose where a section of pipeline is replaced with a turbine-generator section. In-line hydroelectric generation does not include (a) pumped storage hydroelectric generation, (b) run of the river hydroelectric generation or (c) any system using the energy from water from a new (after January 1, 2009) diversion from any river or stream. [Provisional – If Included]

(2) Except with the written consent of the Company, which consent shall not be unreasonably withheld, each physical address (defined as a single residential address or a single tax map key if a commercial or industrial facility) may not have more than one Facility of the same technology type contracted under this Schedule FIT.

(3) This Schedule FIT shall not apply to an existing generating facility currently selling electric energy to the Company under a purchase power agreement, or with an existing standard interconnection agreement with the Company ("Existing Projects"). Such Existing Projects shall not be eligible to sell electric energy to the Company under this Schedule FIT.

(4) Notwithstanding the foregoing, if a customer under the Net Energy Metering Program ("NEM Program") seeks to install an additional generation facility at the same site as an existing net energy metering system, but wishes to keep such existing net energy metering system under the NEM Program and sell the electric energy from the additional generation facility to the Company under this Schedule FIT, the additional generation facility shall be separately metered, provided that such additional generating facility satisfies the definition of "Facility" under this Schedule.

(5) Any Facility selling electric energy to the Company under this Schedule FIT shall sell all the electric energy it produces above any electric energy produced for Seller's own energy consumption, to the Company for the entire term of the Schedule FIT Agreement. A Seller may not sell electric energy to third parties or renegotiate with the Company for any changes to the Schedule FIT Agreement during the term of such Schedule FIT Agreement.

C. Seller Participation:

Participation under this Schedule FIT will be available on a prioritized queue basis as determined by the Company with the concurrence of the Independent Observer (the independent third party retained by the Company and approved by the Hawaii Public Utilities Commission ("Commission") to oversee the initial development and subsequent administration of the Company's queuing and interconnection procedures). Availability of service under this Schedule FIT shall be closed to new Sellers once the designated queue capacity is filled. Should additional Sellers express interest in this Schedule FIT after the designated queue capacity is filled, the Company will maintain

a list of interested Sellers, ranked and prioritized in a reserve queue under this Schedule FIT. Sellers on this reserve queue will be allowed to participate under this Schedule FIT according to their rank order when sufficient capacity becomes available, either due to the start of a new subscription period or if other Sellers who have entered into an Agreement withdraw or fail to meet project development deadlines as specified in this Schedule FIT. The Company shall review and adjust the annual system limits pursuant to procedures adopted by the Commission.

D. Interconnection:

All Facilities shall be designed to interconnect and operate in parallel with the Company's system without adversely affecting the operations of its customers and without presenting safety hazards to the Company's or other customers' personnel. The Facilities and the interconnection systems must be in compliance with all applicable safety and performance standards of the National Electric Code (NEC), the Institute of Electrical and Electronics Engineers (IEEE), the Company's interconnection standards and procedures provided in Rule 14, Section H, and Rule 19, as amended from time to time, and also subject to any other requirements as may be specified in the Schedule FIT Agreement.

E. Schedule FIT Agreement:

Sellers selected to participate under this Schedule FIT shall complete and sign the standard Schedule FIT agreement ("Schedule FIT Agreement") provided in Appendix I (Form of Schedule FIT Tier 3 Agreement). The Schedule FIT Agreement shall specify the "Schedule FIT Contract Capacity" based on the Design Capacity (in kW AC) of the Facility.

F. Metering:

The Company shall, at its expense, install and own the requisite meter(s) to record the flow of electric energy in each direction. The Seller shall, at its expense, provide, install and maintain all conductors, service switches, fuses, meter sockets, meter instrument transformer housing and mountings, switchboard meter test buses, meter panels and similar devices required for service connection and meter installations on the Seller's premises in accordance with the Company's Rule 14, Section A.2, as amended from time to time. Electric energy delivered to the Seller by the Company will be metered separately from the electric energy delivered by the Seller to the Company, either by use of multiple meters or a meter capable of separately recording the net inflow and outflow of electricity.

G. Purchase of Renewable Energy Delivered by Seller to Company:

(1) The Company shall pay for each kilowatt-hour ("kWh") of electric energy delivered to the Company by Seller as follows:

Renewable Generator Type and Size	FIT Energy Payment Rate (¢/kWh)
Tier 3 PV > 500 kW and ≤ the lesser of 5 MW or 1% of the system peak load	19.7
Tier 3 CSP > 500 kW and ≤ the lesser of 5 MW or 1% of the system peak load	31.6
Tier 3 On-Shore Wind > 100 kW and ≤ the lesser of 5 MW or 1% of the system peak load	12.0
Tier 3 In-line Hydro > 100kW and ≤ the lesser of 5 MW or 1% of the system peak load	11.1 [Provisional - If Included]
Baseline FIT Rate (based on Tier XX Technology FIT Rate for Oahu)	To be determined

(2) The energy payment rates specified in paragraph G(1) for solar energy technologies (PV and CSP) are based on the 35% Hawaii state renewable energy technologies income tax credit as prescribed in the Hawaii state tax code, Hawaii Revised Statutes ("HRS") Section 235-12.5. If the Seller provides written documentation by the In-Service Date that the Seller will elect the tax credit refund provision for solar energy technologies as provided in HRS Section 235-12.5(g), the Company shall pay for each kilowatt-hour ("kWh") of electric energy delivered to the Company by Seller as follows:

Renewable Generator Type and Size	FIT Energy Payment Rate (¢/kWh)
Tier 3 PV > 500 kW and ≤ the lesser of 5 MW or 1% of the system peak load	23.6
Tier 3 CSP > 500 kW and ≤ the lesser of 5 MW or 1% of the system peak load	33.6

The Seller will provide a copy of the actual tax filing to the State Department of Taxation documenting this refund election within 30 days of the filing. If the actual tax filing shows that the 35% tax credit was taken, the FIT energy payment rate from the date of the filing will revert to that specified in paragraph G(1), and the overpayment to the Seller for electric energy purchased under this Schedule FIT for all previous months will be netted against future energy payments to Seller.

(3) The rates paid by the Company for the electric energy purchased under this Schedule FIT may be adjusted periodically as ordered and approved by the Commission. The Seller shall receive the FIT energy payment rate in effect at the time of execution of the Schedule FIT Agreement for the entire term of the Schedule FIT Agreement, provided, however, that the FIT energy payment rate may be modified by the Commission during the term of the Agreement if it is determined by the Commission to be necessary to maintain the viability of Seller's development and operation of Facility due to changes in federal or state tax laws.

H. Baseline FIT Rate

Facilities utilizing a Renewable Portfolio Standards ("RPS") eligible technology as defined in Hawaii Revised Statutes Section 269-91 (with the exception of biofuel projects and hybrid projects using conventional fuels or biofuels) and which are not eligible for one of the specific FIT energy payment rates set forth in this Schedule FIT, may apply for the "Baseline FIT Rate". The Baseline FIT Rate means the rate equal to the lowest specified FIT energy payment rate for any project size or technology on any island. Projects using the Baseline FIT Rate cannot exceed the maximum size limits for Facilities.

I. Term:

Except as otherwise provided in the Schedule FIT Agreement, the term of the Schedule FIT Agreement will commence on the Execution Date and will continue for twenty (20) years, from the In-Service Date under the Schedule FIT Agreement.

J. Electric Energy Delivered to the Seller by the Company:

Electric energy delivered to the Seller by the Company shall be billed under the Company's applicable rate schedule.

K. Allowed Project Development Timeframe:

Facilities must be placed into operation within the timeframes specified in the Schedule FIT Agreement and measured from the Execution Date of the Schedule FIT Agreement. Should a Facility fail to meet the allowed project development timeframe, the Schedule FIT Agreement will be terminated and any fees and security deposits (*e.g.*, the reservation fee) paid to the Company by Seller will be forfeited. Sellers may request an extension of the allowed project development timeframe in accordance with the terms of Schedule FIT Agreement.

L. Schedule FIT Fees and Deposits:

(1) Application Fee. At the time the Seller's application for service under this Schedule FIT is submitted, the Seller shall pay to Company a one-time, non-refundable application fee of $2,500.

(2) Reservation Fee. A reservation fee shall be submitted by the Seller to the Company within five business days after successful submission of the application for service under this Schedule FIT. The reservation fee will be refunded to the Seller following the In-Service Date if the Seller meets the Guaranteed In-Service Date as set forth in the Schedule FIT Agreement. However, the reservation fee will be forfeited if the Seller fails to meet the Guaranteed In-Service Date as provided in the Schedule FIT Agreement. The reservation fee amount shall be determined by multiplying the Schedule FIT Design Capacity in kilowatts by $ 15 per kilowatt.

(3) Operating Period Security: A Seller shall provide Operating Period Security in the amount of $40/kW based on the original Contract Capacity, due within five (5) Days of the In-Service Date as provided in the Schedule FIT Agreement.

(4) Service Charge. A non-refundable service charge of $25.00 per month shall be charged to the Seller for the metering, billing, and administration of the Seller's purchased power under the Schedule FIT Agreement.

M. Participation in other Company Programs:

To avoid circumstances where a Seller is receiving duplicative compensation, Sellers with multiple generators may not participate in any other Company interruptible or NEM Programs unless the multiple generators can be segregated electrically from each other and Seller demonstrates that one generator or generators is/are being used to provide electric energy to the Company for sale under the Schedule FIT and the other generator(s) is/are used exclusively for standby generation and to participate in a Company interruptible service program.

SCHEDULE FIT TARIFF
TIER 3

HAWAII

SCHEDULE FIT TIER 3
HAWAII ELECTRIC LIGHT COMPANY, INC. ("COMPANY")

Feed-In Tariff - Purchases from Tier 3 Eligible Renewable Energy Generating Facilities

A. Availability:

This schedule feed-in tariff ("FIT") for Tier 3 Eligible Renewable Energy Generating Facilities ("Schedule FIT") is available to customers, individuals, and independent power producers ("Sellers") who wish to sell to the Company electric energy from a Facility (as defined in Section B, below). This Schedule FIT sets forth the program eligibility, rates, and the terms and conditions for the sale of electric energy to the Company under this Schedule FIT.

B. Eligibility:

(1) An eligible renewable energy generating facility under this Schedule FIT is an electric energy generating facility which meets the following criteria ("Facility"):

(a) Sells electric energy to the Company; and

(b) With respect to Tier 3 Facilities, is a new:

(i) Photovoltaic ("PV") system with a Design Capacity (defined as the capacity of the generator in kilowatts ("kW") as established by the manufacturer that is available for use at the Facility to meet customer load and/or exported to the Company system for sale to the Company under Schedule FIT) (alternating current or "AC") greater than 250kW and up to and including the lesser of 2.72 MW (2,720 kW) or 1% of the system peak load; or

(ii) Concentrated Solar Power ("CSP") system with a Design Capacity (AC) greater than 500 kW and up to and including the lesser of 2.72 MW (2,720 kW) or 1% of the system peak load; or

(iii) In-line hydropower system with a Design Capacity (AC) greater than 100 kW and up to and including the lesser of 2.72 MW (2,720 kW) or 1% of the system peak load. [Provisional – If Included]

(c) For purposes of this Schedule FIT, the following definitions shall apply:

(i) CSP is defined as a Facility that uses mirrors or lenses to concentrate the sun's heat in order to generate electricity.

(ii) In-line hydropower is defined as a hydroelectric Facility that utilizes energy from a water pipeline system that is designed primarily to serve another

functional purpose where a section of pipeline is replaced with a turbine-generator section. In-line hydroelectric generation does not include (a) pumped storage hydroelectric generation, (b) run of the river hydroelectric generation or (c) any system using the energy from water from a new (after January 1, 2009) diversion from any river or stream. [Provisional – If Included]

(2) Except with the written consent of the Company, which consent shall not be unreasonably withheld, each physical address (defined as a single residential address or a single tax map key if a commercial or industrial facility) may not have more than one Facility of the same technology type contracted under this Schedule FIT.

(3) This Schedule FIT shall not apply to an existing generating facility currently selling electric energy to the Company under a purchase power agreement, or with an existing standard interconnection agreement with the Company ("Existing Projects"). Such Existing Projects shall not be eligible to sell electric energy to the Company under this Schedule FIT.

(4) Notwithstanding the foregoing, if a customer under the Net Energy Metering Program ("NEM Program") seeks to install an additional generation facility at the same site as an existing net energy metering system, but wishes to keep such existing net energy metering system under the NEM Program and sell the electric energy from the additional generation facility to the Company under this Schedule FIT, the additional generation facility shall be separately metered, provided that such additional generating facility satisfies the definition of "Facility" under this Schedule.

(5) Any Facility selling electric energy to the Company under this Schedule FIT shall sell all the electric energy it produces above any electric energy produced for Seller's own energy consumption, to the Company for the entire term of the Schedule FIT Agreement. A Seller may not sell electric energy to third parties or renegotiate with the Company for any changes to the Schedule FIT Agreement during the term of such Schedule FIT Agreement.

C. Seller Participation:

Participation under this Schedule FIT will be available on a prioritized queue basis as determined by the Company with the concurrence of the Independent Observer (the independent third party retained by the Company and approved by the Hawaii Public Utilities Commission ("Commission") to oversee the initial development and subsequent administration of the Company's queuing and interconnection procedures). Availability of service under this Schedule FIT shall be closed to new Sellers once the designated queue capacity is filled. Should additional Sellers express interest in this Schedule FIT after the designated queue capacity is filled, the Company will maintain a list of interested Sellers, ranked and prioritized in a reserve queue under this Schedule FIT. Sellers on this reserve queue will be allowed to participate under this Schedule FIT according to their rank order when sufficient capacity becomes available, either due to the start of a new subscription period

or if other Sellers who have entered into an Agreement withdraw or fail to meet project development deadlines as specified in this Schedule FIT. The Company shall review and adjust the annual system limits pursuant to procedures adopted by the Commission.

D. Interconnection:

All Facilities shall be designed to interconnect and operate in parallel with the Company's system without adversely affecting the operations of its customers and without presenting safety hazards to the Company's or other customers' personnel. The Facilities and the interconnection systems must be in compliance with all applicable safety and performance standards of the National Electric Code (NEC), the Institute of Electrical and Electronics Engineers (IEEE), the Company's interconnection standards and procedures provided in Rule 14, Section H, and Rule 19, as amended from time to time, and also subject to any other requirements as may be specified in the Schedule FIT Agreement.

E. Schedule FIT Agreement:

Sellers selected to participate under this Schedule FIT shall complete and sign the standard Schedule FIT agreement ("Schedule FIT Agreement") provided in Appendix I (Form of Schedule FIT Tier 3 Agreement). The Schedule FIT Agreement shall specify the "Schedule FIT Contract Capacity" based on the Design Capacity (in kW AC) of the Facility.

F. Metering:

The Company shall, at its expense, install and own the requisite meter(s) to record the flow of electric energy in each direction. The Seller shall, at its expense, provide, install and maintain all conductors, service switches, fuses, meter sockets, meter instrument transformer housing and mountings, switchboard meter test buses, meter panels and similar devices required for service connection and meter installations on the Seller's premises in accordance with the Company's Rule 14, Section A.2, as amended from time to time. Electric energy delivered to the Seller by the Company will be metered separately from the electric energy delivered by the Seller to the Company, either by use of multiple meters or a meter capable of separately recording the net inflow and outflow of electricity.

G. Purchase of Renewable Energy Delivered by Seller to Company:

(1) The Company shall pay for each kilowatt-hour ("kWh") of electric energy delivered to the Company by Seller as follows:

Renewable Generator Type and Size	FIT Energy Payment Rate (¢/kWh)
Tier 3 PV > 250 kW and ≤ the lesser of 2.72 MW or 1% of the system peak load	19.7
Tier 3 CSP > 500 kW and ≤ the lesser of 2.72 MW or 1% of the system peak load	31.6
Tier 3 In-line Hydro > 100kW and ≤ the lesser of 2.72 MW or 1% of the system peak load	11.1 [Provisional - If Included]
Baseline FIT Rate (based on Tier XX Technology FIT Rate for Oahu)	To be determined

(2) The energy payment rates specified in paragraph G(1) for solar energy technologies (PV and CSP) are based on the 35% Hawaii state renewable energy technologies income tax credit as prescribed in the Hawaii state tax code, Hawaii Revised Statutes ("HRS") Section 235-12.5. If the Seller provides written documentation by the In-Service Date that the Seller will elect the tax credit refund provision for solar energy technologies as provided in HRS Section 235-12.5(g), the Company shall pay for each kilowatt-hour ("kWh") of electric energy delivered to the Company by Seller as follows:

Renewable Generator Type and Size	FIT Energy Payment Rate (¢/kWh)
Tier 3 PV > 500 kW and ≤ the lesser of 5 MW or 1% of the system peak load	23.6
Tier 3 CSP > 500 kW and ≤ the lesser of 5 MW or 1% of the system peak load	33.6

The Seller will provide a copy of the actual tax filing to the State Department of Taxation documenting this refund election within 30 days of the filing. If the actual tax filing shows that the 35% tax credit was taken, the FIT energy payment rate from the date of the filing will revert to that specified in paragraph G(1), and the overpayment to the Seller for electric energy purchased under this Schedule FIT for all previous months will be netted against future energy payments to Seller.

(3) The rates paid by the Company for the electric energy purchased under this Schedule FIT may be adjusted periodically as ordered and approved by the Commission. The Seller shall receive the FIT energy payment rate in effect at the time of execution of the Schedule FIT Agreement for the entire term of the Schedule FIT Agreement, provided, however, that the FIT energy payment rate may be modified by the Commission during the term of the Agreement if it is determined by the Commission to be necessary to maintain the viability of Seller's development and operation of Facility due to changes in federal or state tax laws.

H. Baseline FIT Rate

Facilities utilizing a Renewable Portfolio Standards ("RPS") eligible technology as defined in Hawaii Revised Statutes Section 269-91 (with the exception of biofuel projects and hybrid projects using conventional fuels or biofuels) and which are not eligible for one of the specific FIT energy payment rates set forth in this Schedule FIT, may apply for the "Baseline FIT Rate". The Baseline FIT Rate means the rate equal to the lowest specified FIT energy payment rate for any project size or technology on any island. Projects using the Baseline FIT Rate cannot exceed the maximum size limits for Facilities.

I. Term:

Except as otherwise provided in the Schedule FIT Agreement, the term of the Schedule FIT Agreement will commence on the Execution Date and will continue for twenty (20) years, from the In-Service Date under the Schedule FIT Agreement.

J. Electric Energy Delivered to the Seller by the Company:

Electric energy delivered to the Seller by the Company shall be billed under the Company's applicable rate schedule.

K. Allowed Project Development Timeframe:

Facilities must be placed into operation within the timeframes specified in the Schedule FIT Agreement and measured from the Execution Date of the Schedule FIT Agreement. Should a Facility fail to meet the allowed project development timeframe, the Schedule FIT Agreement will be terminated and any fees and security deposits (*e.g.*, the reservation fee) paid to the Company by Seller will be forfeited. Sellers may request an extension of the allowed project development timeframe in accordance with the terms of Schedule FIT Agreement.

L. Schedule FIT Fees and Deposits:

(1) Application Fee. At the time the Seller's application for service under this Schedule FIT is submitted, the Seller shall pay to Company a one-time, non-refundable application fee of $2,500.

(2) Reservation Fee. A reservation fee shall be submitted by the Seller to the Company within five business days after successful submission of the application for service under this Schedule FIT. The reservation fee will be refunded to the Seller following the In-Service Date if the Seller meets the Guaranteed In-Service Date as set forth in the Schedule FIT Agreement. However, the reservation fee will be forfeited if the Seller fails to meet the Guaranteed In-Service Date as provided in the Schedule FIT Agreement. The reservation fee amount shall be determined by multiplying the Schedule FIT Design Capacity in kilowatts by $ 15 per kilowatt.

(3) Operating Period Security: A Seller shall provide Operating Period Security in the amount of $40/kW based on the original Contract Capacity, due within five (5) Days of the In-Service Date as provided in the Schedule FIT Agreement.

(4) Service Charge. A non-refundable service charge of $25.00 per month shall be charged to the Seller for the metering, billing, and administration of the Seller's purchased power under the Schedule FIT Agreement.

M. Participation in other Company Programs:

To avoid circumstances where a Seller is receiving duplicative compensation, Sellers with multiple generators may not participate in any other Company interruptible or NEM Programs unless the multiple generators can be segregated electrically from each other and Seller demonstrates that one generator or generators is/are being used to provide electric energy to the Company for sale under the Schedule FIT and the other generator(s) is/are used exclusively for standby generation and to participate in a Company interruptible service program.

SCHEDULE FIT TARIFF
TIER 3

MAUI

MAUI DIVISION

SCHEDULE FIT TIER 3
MAUI ELECTRIC COMPANY, LIMITED. ("COMPANY")

Feed-In Tariff - Purchases from Tier 3 Eligible Renewable Energy Generating Facilities

A. Availability:

This schedule feed-in tariff ("FIT") for Tier 3 Eligible Renewable Energy Generating Facilities ("Schedule FIT") is available to customers, individuals, and independent power producers ("Sellers") who wish to sell to the Company electric energy from a Facility (as defined in Section B, below). This Schedule FIT sets forth the program eligibility, rates, and the terms and conditions for the sale of electric energy to the Company under this Schedule FIT.

B. Eligibility:

(1) An eligible renewable energy generating facility under this Schedule FIT is an electric energy generating facility which meets the following criteria ("Facility"):

(a) Sells electric energy to the Company; and

(b) With respect to Tier 3 Facilities, is a new:

(i) Photovoltaic ("PV") system with a Design Capacity (defined as the capacity of the generator in kilowatts ("kW") as established by the manufacturer that is available for use at the Facility to meet customer load and/or exported to the Company system for sale to the Company under Schedule FIT) (alternating current or "AC") greater than 250kW and up to and including the lesser of 2.72 MW (2,720 kW) or 1% of the system peak load; or

(ii) Concentrated Solar Power ("CSP") system with a Design Capacity (AC) greater than 500 kW and up to and including the lesser of 2.72 MW (2,720 kW) or 1% of the system peak load; or

(iii) In-line hydropower system with a Design Capacity (AC) greater than 100 kW and up to and including the lesser of 2.72 MW (2,720 kW) or 1% of the system peak load. [Provisional – If Included]

(c) For purposes of this Schedule FIT, the following definitions shall apply:

(i) CSP is defined as a Facility that uses mirrors or lenses to concentrate the sun's heat in order to generate electricity.

(ii) In-line hydropower is defined as a hydroelectric Facility that utilizes energy from a water pipeline system that is designed primarily to serve another functional purpose where a section of pipeline is replaced with a turbine-generator section. In-line hydroelectric generation does not include (a) pumped storage hydroelectric generation, (b) run of the river hydroelectric generation or (c) any system using the energy from water from a new (after January 1, 2009) diversion from any river or stream. [Provisional – If Included]

(2) Except with the written consent of the Company, which consent shall not be unreasonably withheld, each physical address (defined as a single residential address or a single tax map key if a commercial or industrial facility) may not have more than one Facility of the same technology type contracted under this Schedule FIT.

(3) This Schedule FIT shall not apply to an existing generating facility currently selling electric energy to the Company under a purchase power agreement, or with an existing standard interconnection agreement with the Company ("Existing Projects"). Such Existing Projects shall not be eligible to sell electric energy to the Company under this Schedule FIT.

(4) Notwithstanding the foregoing, if a customer under the Net Energy Metering Program ("NEM Program") seeks to install an additional generation facility at the same site as an existing net energy metering system, but wishes to keep such existing net energy metering system under the NEM Program and sell the electric energy from the additional generation facility to the Company under this Schedule FIT, the additional generation facility shall be separately metered, provided that such additional generating facility satisfies the definition of "Facility" under this Schedule.

(5) Any Facility selling electric energy to the Company under this Schedule FIT shall sell all the electric energy it produces above any electric energy produced for Seller's own energy consumption, to the Company for the entire term of the Schedule FIT Agreement. A Seller may not sell electric energy to third parties or renegotiate with the Company for any changes to the Schedule FIT Agreement during the term of such Schedule FIT Agreement.

C. Seller Participation:

Participation under this Schedule FIT will be available on a prioritized queue basis as determined by the Company with the concurrence of the Independent Observer (the independent third party retained by the Company and approved by the Hawaii Public Utilities Commission ("Commission") to oversee the initial development and subsequent administration of the Company's queuing and interconnection procedures). Availability of service under this Schedule FIT shall be closed to new Sellers once the designated queue capacity is filled. Should additional Sellers express interest in this Schedule FIT after the designated queue capacity is filled, the Company will maintain a list of interested Sellers, ranked and prioritized in a reserve queue under this Schedule FIT. Sellers

on this reserve queue will be allowed to participate under this Schedule FIT according to their rank order when sufficient capacity becomes available, either due to the start of a new subscription period or if other Sellers who have entered into an Agreement withdraw or fail to meet project development deadlines as specified in this Schedule FIT. The Company shall review and adjust the annual system limits pursuant to procedures adopted by the Commission.

D. Interconnection:

All Facilities shall be designed to interconnect and operate in parallel with the Company's system without adversely affecting the operations of its customers and without presenting safety hazards to the Company's or other customers' personnel. The Facilities and the interconnection systems must be in compliance with all applicable safety and performance standards of the National Electric Code (NEC), the Institute of Electrical and Electronics Engineers (IEEE), the Company's interconnection standards and procedures provided in Rule 14, Section H, and Rule 19, as amended from time to time, and also subject to any other requirements as may be specified in the Schedule FIT Agreement.

E. Schedule FIT Agreement:

Sellers selected to participate under this Schedule FIT shall complete and sign the standard Schedule FIT agreement ("Schedule FIT Agreement") provided in Appendix I (Form of Schedule FIT Tier 3 Agreement). The Schedule FIT Agreement shall specify the "Schedule FIT Contract Capacity" based on the Design Capacity (in kW AC) of the Facility.

F. Metering:

The Company shall, at its expense, install and own the requisite meter(s) to record the flow of electric energy in each direction. The Seller shall, at its expense, provide, install and maintain all conductors, service switches, fuses, meter sockets, meter instrument transformer housing and mountings, switchboard meter test buses, meter panels and similar devices required for service connection and meter installations on the Seller's premises in accordance with the Company's Rule 14, Section A.2, as amended from time to time. Electric energy delivered to the Seller by the Company will be metered separately from the electric energy delivered by the Seller to the Company, either by use of multiple meters or a meter capable of separately recording the net inflow and outflow of electricity.

G. Purchase of Renewable Energy Delivered by Seller to Company:

(1) The Company shall pay for each kilowatt-hour ("kWh") of electric energy delivered to the Company by Seller as follows:

Renewable Generator Type and Size	FIT Energy Payment Rate (¢/kWh)
Tier 3 PV > 250 kW and ≤ the lesser of 2.72 MW or 1% of the system peak load	19.7
Tier 3 CSP > 500 kW and ≤ the lesser of 2.72 MW or 1% of the system peak load	31.6
Tier 3 In-line Hydro > 100kW and ≤ the lesser of 2.72 MW or 1% of the system peak load	11.1 [Provisional - If Included]
Baseline FIT Rate (based on Tier XX Technology FIT Rate for Oahu)	To be determined

(2) The energy payment rates specified in paragraph G(1) for solar energy technologies (PV and CSP) are based on the 35% Hawaii state renewable energy technologies income tax credit as prescribed in the Hawaii state tax code, Hawaii Revised Statutes ("HRS") Section 235-12.5. If the Seller provides written documentation by the In-Service Date that the Seller will elect the tax credit refund provision for solar energy technologies as provided in HRS Section 235-12.5(g), the Company shall pay for each kilowatt-hour ("kWh") of electric energy delivered to the Company by Seller as follows:

Renewable Generator Type and Size	FIT Energy Payment Rate (¢/kWh)
Tier 3 PV > 500 kW and ≤ the lesser of 5 MW or 1% of the system peak load	23.6
Tier 3 CSP > 500 kW and ≤ the lesser of 5 MW or 1% of the system peak load	33.6

The Seller will provide a copy of the actual tax filing to the State Department of Taxation documenting this refund election within 30 days of the filing. If the actual tax filing shows that the 35% tax credit was taken, the FIT energy payment rate from the date of the filing will revert to that specified in paragraph G(1), and the overpayment to the Seller for electric energy purchased under this Schedule FIT for all previous months will be netted against future energy payments to Seller.

(3) The rates paid by the Company for the electric energy purchased under this Schedule FIT may be adjusted periodically as ordered and approved by the Commission. The Seller shall receive the FIT energy payment rate in effect at the time of execution of the Schedule FIT Agreement for the entire term of the Schedule FIT Agreement, provided, however, that the FIT energy payment rate may be modified by the Commission during the term of the Agreement if it is determined by the Commission to be necessary to maintain the viability of Seller's development and operation of Facility due to changes in federal or state tax laws.

H. Baseline FIT Rate

Facilities utilizing a Renewable Portfolio Standards ("RPS") eligible technology as defined in Hawaii Revised Statutes Section 269-91 (with the exception of biofuel projects and hybrid projects using conventional fuels or biofuels) and which are not eligible for one of the specific FIT energy payment rates set forth in this Schedule FIT, may apply for the "Baseline FIT Rate". The Baseline FIT Rate means the rate equal to the lowest specified FIT energy payment rate for any project size or technology on any island. Projects using the Baseline FIT Rate cannot exceed the maximum size limits for Facilities.

I. Term:

Except as otherwise provided in the Schedule FIT Agreement, the term of the Schedule FIT Agreement will commence on the Execution Date and will continue for twenty (20) years, from the In-Service Date under the Schedule FIT Agreement.

J. Electric Energy Delivered to the Seller by the Company:

Electric energy delivered to the Seller by the Company shall be billed under the Company's applicable rate schedule.

K. Allowed Project Development Timeframe:

Facilities must be placed into operation within the timeframes specified in the Schedule FIT Agreement and measured from the Execution Date of the Schedule FIT Agreement. Should a Facility fail to meet the allowed project development timeframe, the Schedule FIT Agreement will be terminated and any fees and security deposits (*e.g.*, the reservation fee) paid to the Company by Seller will be forfeited. Sellers may request an extension of the allowed project development timeframe in accordance with the terms of Schedule FIT Agreement.

L. Schedule FIT Fees and Deposits:

(1) Application Fee. At the time the Seller's application for service under this Schedule FIT is submitted, the Seller shall pay to Company a one-time, non-refundable application fee of $2,500.

(2) Reservation Fee. A reservation fee shall be submitted by the Seller to the Company within five business days after successful submission of the application for service under this Schedule FIT. The reservation fee will be refunded to the Seller following the In-Service Date if the Seller meets the Guaranteed In-Service Date as set forth in the Schedule FIT Agreement. However, the reservation fee will be forfeited if the Seller fails to meet the Guaranteed In-Service Date as provided in the Schedule FIT Agreement. The reservation fee amount shall be determined by multiplying the Schedule FIT Design Capacity in kilowatts by $ 15 per kilowatt.

(3) Operating Period Security: A Seller shall provide Operating Period Security in the amount of $40/kW based on the original Contract Capacity, due within five (5) Days of the In-Service Date as provided in the Schedule FIT Agreement.

(4) Service Charge. A non-refundable service charge of $25.00 per month shall be charged to the Seller for the metering, billing, and administration of the Seller's purchased power under the Schedule FIT Agreement.

M. Participation in other Company Programs:

To avoid circumstances where a Seller is receiving duplicative compensation, Sellers with multiple generators may not participate in any other Company interruptible or NEM Programs unless the multiple generators can be segregated electrically from each other and Seller demonstrates that one generator or generators is/are being used to provide electric energy to the Company for sale under the Schedule FIT and the other generator(s) is/are used exclusively for standby generation and to participate in a Company interruptible service program.

SCHEDULE FIT
STANDARD AGREEMENT
FOR
TIER 3

Hawaiian Electric Companies
Tier 3 Feed-In Tariff
Power Purchase Agreement

SCHEDULE FIT TIER 3 POWER PURCHASE AGREEMENT

THIS SCHEDULE FIT TIER 3 POWER PURCHASE AGREEMENT ("Agreement") is made this ____ day of _____, 20___ (the "Execution Date"), by and between **[INSERT ONE OF THE FOLLOWING AS APPLICABLE: Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc. or Maui Electric Company, Limited]** (hereinafter called the "Company") and _____ (hereinafter called the "Seller").

WHEREAS, Company is an operating electric public utility, subject to the Hawaii Public Utilities Law (Hawaii Revised Statutes, Chapter 269) and the rules and regulations of the Hawaii Public Utilities Commission (hereinafter called the "PUC"); and

WHEREAS, the Company System is operated as an independent power grid and must both maximize system reliability for its customers by ensuring that sufficient generation is available and meet the requirements for voltage stability, frequency stability, and reliability standards; and

WHEREAS, Seller desires to build, own, and operate a renewable energy facility that is classified as an eligible resource under Hawaii's Renewable Portfolio Standards Statute (codified as Hawaii Revised Statutes (HRS) 269-91 through 269-95; and

WHEREAS, Seller understands the need to use all commercially reasonable efforts to maximize the overall reliability of the Company System; and

WHEREAS, Facility will be located at _____, State of Hawaii and is more fully described in Attachment A (Description of Generation and Conversion Facility) and Attachment B (Facility Owned by Seller) attached hereto and made a part hereof; and

WHEREAS, Seller desires to sell to Company electric energy generated by the Facility, and Company agrees to purchase such electric energy from Seller, pursuant to the Schedule FIT Tier 3 and upon the terms and conditions set forth herein.

NOW, THEREFORE, in consideration of the premises and the respective promises herein, Company and Seller hereby agree as follows:

DEFINITIONS

For the purposes of this Agreement, the following capitalized terms shall have the meanings set forth below:

"Acceptance Test": A test conducted by Seller and, at Company's option, witnessed by Company, within thirty (30) Days of completion of all Interconnection Facilities and in accordance with criteria and test procedures determined by Company and Seller as set forth below as set forth in Section 1(J) (Acceptance Test Procedure) of Attachment G (Company-Owned Interconnection Facilities), to determine conformance with Article 3 (Facility Owned and/or Operated by Seller) and Attachment G (Company-Owned Interconnection Facilities) and Good Engineering and Operating Practices. Attachment N (Acceptance Test General Criteria) provides general criteria to be included in the written protocol for the Acceptance Test. Successful completion of the Acceptance Test shall be a condition precedent for the performance of the Control System Acceptance Test and the In-Service Date.

"Actual Output": The total quantity of electric energy (measured in kilowatt hours) produced by Facility over a given time period and delivered to the Point of Interconnection, as measured by the revenue meter.

"Agreement": Shall have the meaning set forth in the preamble to this Agreement.

"Allowed Capacity": Shall have the meaning set forth in Section 5.E of Attachment A (Description of Generation and Conversion Facility) to this Agreement.

"Annual Contract Energy": [redacted] MWh for a Contract Year, which represents Seller's estimate of expected annual average electric energy deliveries to Company under this Agreement over the Initial Term. **[TO BE COMPLETED BY SELLER PRIOR TO EXECUTION]**

"Arbitration Rules": Shall have the meaning set forth in Section 28.2(B) (Arbitration).

"As-Available Energy": Electric energy provided to Company on an unscheduled basis as Seller determines it to be available from its Facility, in accordance with the terms and conditions of this Agreement, rather than at prearranged times and in prearranged amounts.

"Base Load Unit": A generating unit that is normally on-line twenty-four (24) hours a Day. This includes any unit that is scheduled to be on-line continuously for a given Day because a unit which is normally a Base Load Unit is on maintenance or otherwise temporarily out of service.

"Base Rate": The primary index rate established from time to time by the Bank of Hawaii in the ordinary course of its business and published by intrabank circular letters or memoranda for the guidance of its loan officers in pricing all of its loans which float with the Base Rate. A change in the Base Rate shall take effect on the date upon which a change in the Base Rate is made effective by the Bank of Hawaii. In the event the Bank of Hawaii no longer establishes a Base Rate, the term "Base Rate" shall mean the primary index rate established by a leading Hawaii financial institution that is the most similar to the former Bank of Hawaii Base Rate.

"Bill of Material": A list of equipment to be installed at the Facility including, but not necessarily limited to, items such as relays, breakers, and switches.

"Business Day": Any calendar day that is not a Saturday, a Sunday, or a federal or Hawaii state holiday.

"Claim": Any claim, suit, action, demand or proceeding.

"Company": Shall have the meaning set forth in the preamble to this Agreement.

"Company-Owned Interconnection Facilities": Shall have the meaning set forth in Section 1(A) (Description of Company-Owned Interconnection Facilities) of Attachment G (Company-Owned Interconnection Facilities).

"Company Dispatch": Company's sole and absolute right, through supervisory equipment, or otherwise, to direct or control, from moment to moment, and in accordance with Good Engineering and Operating Practices, the rate of delivery of electric energy offered by Seller to Company, subject to the operating constraints of Facility and as permitted under this Agreement.

"Company System": The electric system owned and operated by Company (to include any non-utility owned facilities) consisting of power plants, transmission and distribution lines, and related equipment for the production and delivery of electric power to the public.

"Company System Operator": The authorized representative of Company who is responsible for carrying out Company Dispatch.

"Competitive Bidding Framework": The Framework for Competitive Bidding contained in Decision and Order No. 23121 issued by the Public Utilities Commission on December 8, 2006 and any subsequent orders providing for modifications from those set forth in the order issued December 8, 2006.

"Construction Milestones": The Reporting Milestones set forth in Attachment L (Reporting Milestones) and the Guaranteed Project Milestones set forth in Attachment K (Guaranteed Project Milestones).

"Construction Start Date": The date on which continuous construction of permanent generation structures begins at the Site.

"Consumer Advocate": Shall have the meaning set forth in Section 24.2 (Confidentiality).

"Consumer Price Index": The Consumer Price Index for All Urban Consumers (CPI-U).

"Contract Capacity": Shall have the meaning set forth in Section 5(B) (Design and Capacity) of Attachment A (Description of Generation and Conversion Facility) to this Agreement.

"Contract Price": The price that Company will pay Seller for electric energy delivered on a monthly basis as set forth in of Attachment J (Energy Purchases by Company) to this Agreement.

"Contract Year": A twelve calendar month period which begins on the first Day of the month coincident with or next following the In-Service Date and, thereafter, anniversaries thereof; provided, however, that, in the event the In-Service Date is not the first Day of the calendar month, the initial Contract Year shall also include the Days from the In-Service Date to the first Day of the succeeding month.

"Contract Year 1": The initial Contract Year.

"Control System Acceptance Test(s)": A test or tests performed on the centralized control system and Curtailment Control Interface of the Facility in accordance with procedures set forth in Section 1(H) (Control System Acceptance Test Procedures) of Attachment B

(Facility Owned by Seller). Attachment O (Control System Acceptance Test Criteria) provides general criteria to be included in the written protocol for the Control System Acceptance Test.

"Curtailment Event": The temporary curtailment, interruption or reduction of deliveries of electric energy from the Facility initiated by Company as a result of circumstances described in Article 8 (Continuity of Service) and Article 9 (Personnel and System Safety) of this Agreement.

"Day": A calendar day.

"Defaulting Party": The Party whose failure, action or breach of its obligations under this Agreement results in an Event of Default under Article 15 (Events of Default) of this Agreement.

"Design Capacity": The capacity of the generator in kilowatts as established by the manufacturer that is available for use at the Facility to meet customer load and/or exported to the Company System for sale to the Company under Schedule FIT Tier 3.

"Dispute": Shall have the meaning set forth in Section 28.1 (Good Faith Negotiations).

"DOD": Shall have the meaning set forth in Section 17.4 (Seller As An Agency of the Department of Defense) of this Agreement.

"DPR": Shall have the meaning set forth in Section 28.2(A) (Arbitration).

"Energy Cost Adjustment Clause": The provision in Company's rate schedules that allows Company to pass through to its customers Company's costs of fuel and purchased power.

"Environmental Credits": Any environmental credit, offset, or other benefit allocated, assigned or otherwise awarded by any Governmental Authority or international agency to Company or Seller based in whole or in part on the fact that the Facility is a non-fossil fuel facility. Such Environmental Credits shall include, but not be limited to, emissions credits, including credits triggered because the Facility does not produce carbon dioxide when generating electric energy, or any renewable electric energy credit, but in all cases shall not mean tax credits.

"Event of Default": Shall have the meaning set forth in Article 15 (Events of Default) of this Agreement.

"Execution Date": The date designated as such on the first page of this Agreement or, if no date is so designated, the date the Parties exchanged executed signature pages to this Agreement.

"Extended Term": The period following expiration of the Initial Term which continues in effect until terminated by either Party pursuant to the terms of this Agreement as further described in Section 12.2 (Extended Term).

"Facility": Seller's renewable electric energy facility that is the subject of this Agreement, including all Seller-Owned Interconnection Facilities and all other equipment, devices, associated appurtenances owned, controlled, operated and managed by Seller in connection with, or to facilitate, the production, generation, transmission, delivery or furnishing of electric energy by Seller to Company and required to interconnect with the Company System.

"FASB": Shall have the meaning set forth in Section 24.1(Financial Compliance).

"FASB ASC 810": Shall have the meaning set forth in Section 24.1 (Financial Compliance).

"Financing Documents": The loan and credit agreements, notes, bonds, indentures, security agreements, lease financing agreements, mortgages, deeds of trust, interest rate exchanges, swap agreements and other documents relating to the development, bridge, construction and/or permanent debt financing for the Facility, including any credit enhancement, credit support, working capital financing, or refinancing documents, and any and all amendments, modifications, or supplements to the foregoing that may be entered into from time to time at the discretion of Seller in connection with development, construction, ownership, leasing, operation or maintenance of the Facility.

"Force Majeure": Shall have the meaning set forth in Section 21.1 (Force Majeure) of this Agreement.

"Forced Outage": An unplanned unit shutdown caused by factors such as automatic or programmed protective trips and operator-initiated trips due to equipment malfunction.

"Good Engineering and Operating Practices": The practices, methods and acts engaged in or approved by a significant portion of the electric utility industry for similarly situated U.S. facilities, considering Company's isolated island setting and

other characteristics, that at a particular time, in the exercise of reasonable judgment in light of the facts known or that reasonably should be known at the time a decision is made, would be expected to accomplish the desired result in a manner consistent with law, regulation, reliability for an island system, safety, environmental protection, economy and expedition. With respect to the Facility, Good Engineering and Operating Practices include, but are not limited to, taking reasonable steps to ensure that:

- Adequate materials, resources and supplies, including fuel, are available to meet the Facility's needs under normal conditions and reasonably anticipated abnormal conditions.

- Sufficient operating personnel are available and are adequately experienced and trained to operate the Facility properly, efficiently and within manufacturer's guidelines and specifications and are capable of responding to emergency conditions.

- Preventive, routine and non-routine maintenance and repairs are performed on a basis that ensures reliable long-term and safe operation, and are performed by knowledgeable, trained and experienced personnel utilizing proper equipment, tools, and procedures.

- Appropriate monitoring and testing is done to ensure equipment is functioning as designed and to provide assurance that equipment will function properly under both normal and emergency conditions.

- Equipment is operated in a manner safe to workers, the general public and the environment and in accordance with equipment manufacturer's specifications, including, without limitation, defined limitations such as steam pressure, temperature, moisture content, chemical content, quality of make-up water, operating voltage, current, frequency, rotational speed, polarity, synchronization, control system limits, etc.

"Governmental Approvals": Shall have the meaning set forth in Section 8 (Government Approvals for Any Company-Owned Interconnection Facilities Constructed by Seller) of Attachment G (Company-Owned Interconnection Facilities).

"Governmental Authority": Any federal, state, local or municipal governmental body; any governmental, quasi-governmental, regulatory or administrative agency, commission, body or other authority exercising or entitled to exercise any administrative, executive, judicial, legislative, policy, regulatory or taxing authority or power; or any court or governmental tribunal.

"Guaranteed In-Service Date": The date specified as such in Attachment K (Guaranteed Project Milestones) of this Agreement, by which Seller guarantees that it will achieve the In-Service Date.

"Guaranteed Project Milestone": Shall have the meaning set forth in Attachment K (Guaranteed Project Milestones) of this Agreement.

"Guaranteed Project Milestone Date": Each of the dates identified as such in Attachment K (Guaranteed Project Milestones).

"Indemnified Company Party": Shall have the meaning set forth in Section 17.1(A) (Personal Injury, Death or Property Damage) of this Agreement.

"Indemnified Seller Party": Shall have the meaning set forth in Section 17.2(A) (Personal Injury, Death or Property Damage)of this Agreement.

"Independent Evaluator": A person empowered, pursuant to Section 23.5 (Failure to Reach Agreement) and Section 23.10 (Dispute) of this Agreement, to resolve disputes due to failure of the Parties to agree on a Performance Standards Revision Document.

"Information": Shall have the meaning set forth in Section 24.1(Financial Compliance).

"In-Service Date": The date that both the Acceptance Test and Control System Acceptance Test(s) for all generating units are deemed by Company to have been successfully completed.

"Initial Term": Shall have the meaning set forth in Section 12.1 (Term).

"Interconnection Facilities": The equipment and devices required to permit the Facility to operate in parallel with and deliver electric energy to the Company System, such as, but not limited to, transmission lines, transformers, switches, and circuit breakers.

"Interconnection Requirements Study" ("IRS"): A study, performed in accordance with the terms of the IRS Letter Agreement and with Article 4 (Interconnection Facilities Owned by Company) and Attachment G (Company-Owned Interconnection Facilities) of this Agreement, to assess the projected interaction of the Facility with the Company System.

"Interconnection Requirements Study Letter Agreement" or "IRS Letter Agreement": The letter agreement and any written, signed amendments thereto, between Company and Seller that describes the scope, schedule, and payment arrangements for the Interconnection Requirements Study.

"Issuer": Shall have the meaning set forth in Section 14.8 (Establishment of Operating Period Security) of this Agreement.

"kV": Kilovolt.

"kW": Kilowatt.

"Land Rights": All easements, rights of way, licenses, leases, surface use agreements and other interests or rights in real estate.

"Laws" All federal, state and local laws, rules, regulations, orders, ordinances, permit conditions and other governmental actions.

"Losses": Any and all direct, indirect or consequential damages, fines, penalties, deficiencies, losses, liabilities (including settlements and judgments), costs, expenses (including reasonable attorneys' fees and court costs) and disbursements.

"Management Meeting": Shall have the meaning set forth in Section 28.1 (Good Faith Negotiations).

"Measured Wind Speed": The arithmetic mean, over any given period of time, of the wind speed readings from each of a Facility's wind turbine anemometers, taken or sampled every two (2) seconds by the Facility's monitoring equipment, in meters per second (m/s).

"MW": Megawatt.

"Non-appealable PUC Approval Order": Shall have the meaning set forth in Section 30.20(B) (Non-appealable PUC Approval Order)of this Agreement.

"Non-defaulting Party": Shall have the meaning set forth in Section 15.4 (Rights of Non-Defaulting Party) of this Agreement.

"Non-performing Party": The Party who is in breach of, or is otherwise failing to perform, its obligations under this Agreement.

"Operating Period Security": Shall have the meaning set forth in Section 14.4 (Operating Period Security) of this Agreement.

"Party": Each of Seller or Company.

"Parties": Seller and Company, collectively.

"Performance Standards": The various performance standards for the operation of the Facility and the delivery of electric energy from the Facility to the Company specified in Section 3 (Performance Standards) of Attachment B (Facility Owned by Seller), as such standards may be revised from time to time pursuant to Article 23 (Process for Addressing Revisions to Performance Standards) of this Agreement.

"Performance Standards Information Request": A written notice from Company to Seller proposing revisions to one or more of the Performance Standards then in effect and requesting information from Seller concerning such proposed revision(s).

"Performance Standards Modifications": For each Performance Standards Revision, any capital improvements, additions, enhancements, replacements, repairs or other operational modifications to the Facility and/or to changes in Seller's operations or maintenance practices necessary to enable the Facility to achieve the performance requirements of such Performance Standards Revision.

"Performance Standards Pricing Impact": Any adjustment in Contract Price in $/MWh necessary to specifically reflect the recovery of the net costs and/or net lost revenues specifically attributable to any Performance Standards Modification necessary to comply with a Performance Standard Revision, which shall consist of the following: (i) recovery of any capital investment (aa) made over a cost recovery period starting after the Performance Standards Revision is made effective following a PUC Performance Standards Revision Order through the end of the Initial Term and (bb) based on a proposed capital structure that is commercially reasonable for such an investment and the return

on investment is at market rates for such an investment or similar investment); (ii) recovery of reasonably expected net additional operating and maintenance costs; and (iii) an adjustment in pricing necessary to compensate Seller for reasonably expected reductions, if any, in the delivery of electric energy to Company under this Agreement, which shall consist of (yy) an increase in payments necessary to compensate Seller for expected reduced electric energy payments under this Agreement; and (zz) to the extent applicable, an increase in payments necessary to compensate Seller for reasonably expected reductions in receipt of Production Tax Credits (pursuant to Section 45 of the Internal Revenue Code) calculated on an after-tax basis.

"Performance Standards Proposal": A written communication from Seller to Company detailing the following with respect to a proposed Performance Standards Revision: (i) a statement as to whether Seller believes that it is technically feasible to comply with the Performance Standards Revision and the basis therefore; (ii) the Performance Standards Modifications proposed by Seller to comply with the Performance Standards Revision; (iii) the capital and incremental operating costs of any necessary technical improvements, and any other incremental net operating or maintenance costs associated with any necessary operational changes, and any expected lost revenues associated with expected reductions in electric energy delivered to Company; (iv) the Performance Standards Pricing Impact of such costs and/or lost revenues; (v) information regarding the effectiveness of such technical improvements or operational modifications; (vi) proposed contractual consequences for failure to comply with the Performance Standard Revision that would be commercially reasonable under the circumstances; and (vii) such other information as may be reasonably required by Company to evaluate Seller's proposals. A Performance Standards Proposal may be issued either in response to a Performance Standards Information Request or on Seller's own initiative.

"Performance Standards Revision": A revision, as specified in a performance Standards Information Request or a Seller-initiated Performance Standards Proposal, to the Performance Standards in effect as of the date of such Request or Proposal.

"Performance Standards Revision Document": A document specifying one or more Performance Standards Revisions and setting forth the changes to the Agreement necessary to implement such Performance Standards Revision(s). A Performance Standards Revision Document may be either a written agreement executed by Company and Seller or as directed by the Independent Evaluator pursuant to Section

23.10 (Dispute) of this Agreement, in the absence of such written agreement.

"Permit Application Filing Date": The Reporting Milestone by which Seller shall file all applications for Permits required for the construction and operation of the Facility as set forth in Attachment L (Reporting Milestone).

"Permits": All permits, licenses, approvals, certificates, entitlements and other authorizations issued by Governmental Authorities required for the construction, ownership and operation of the Facility, and all amendments, modifications, supplements, general conditions and addenda thereto.

"Point of Interconnection": The point of delivery of electric energy supplied by Seller to Company where the Facility interconnects with the Company System.

"Power Curve": The manufacturer-warranted power curve.

"Project": The Facility as described in Attachment A (Description of Generation and Conversion Facility).

"Proprietary Rights": Shall have the meaning set forth in Section 30.17 (Proprietary Rights) of this Agreement.

"PUC": Shall have the meaning set forth in the Recitals.

"PUC Performance Standards Revision Order": The decision and order of the PUC approving the application or motion by the Parties seeking (i) approval of the Performance Standards Revision in question and the associated Performance Standards Revision Document, (ii) finding that the impact of the changes to the Contract Price on Company's revenue requirements is reasonable, and (iii) approval to include the costs arising out of pricing changes in Company's Energy Cost Adjustment Clause (or equivalent).

"PUC's Standards": Standards for Small Power Production and Cogeneration in the State of Hawaii, issued by the Public Utilities Commission of the State of Hawaii, Chapter 74 of Title 6, Hawaii Administrative Rules, currently in effect and as may be amended from time to time.

"PURPA": Public Utility Regulatory Policies Act of 1978 (P.L. 95-617) as amended from time to time and as applied in Hawaii by the Public Utilities Commission.

"Qualifying Facility": As defined in the Public Utility Regulatory Policies Act of 1978 and the regulations issued thereunder.

"Recipient": Shall have the meaning set forth in Section 24.2 (Confidentiality).

"Renewable Portfolio Standards" ("RPS"): The Hawaii law that mandates that Company and its subsidiaries generate or purchase certain amounts of their net electricity sales over time from qualified renewable resources. The RPS requirements in Hawaii are currently codified as Hawaii Revised Statutes (HRS) 269-91 through 269-95.

"Reporting Milestones": Shall have the meaning set forth in Attachment L (Reporting Milestones).

"Reservation Fee": The refundable reservation fee defined in Schedule FIT Tier 3.

"Schedule FIT Tier 3": The schedule feed-in tariff for Tier 3 eligible renewable energy generating facilities.

"Seller": Shall have the meaning set forth in the preamble to this Agreement.

"Seller-Owned Interconnection Facilities": The Interconnection Facilities constructed and owned by Seller.

"Site": The parcel of real property on which the Facility will be constructed and located, together with any Land Rights reasonably necessary for the construction, operation and maintenance of the Facility. The Site is identified in Attachment A (Description of Generation and Conversion Facility) to this Agreement.

"SOX 404": Shall have the meaning set forth in Section 24.1 (Financial Compliance).

"State": Shall have the meaning set forth in Section 17.3 (Seller As An Agency of the State) of this Agreement.

"Term": Shall mean, collectively, the Initial Term and the Extended Term (if any).

"Termination Damages": Shall have the meaning set forth in Section 15.4 (Rights of the Non-Defaulting Party) and shall be

calculated in accordance with Article 16 (Damages in the Event of Termination by Company)of this Agreement.

"Third Party": Any person or entity other than Company or Seller, and includes, but is not limited to, any subsidiary or affiliate of Seller.

"Total Actual Interconnection Cost": Actual costs for the Interconnection Facilities, to be designed, engineered and constructed by Company, as provided in Attachment G (Company-Owned Interconnection Facilities).

"Total Estimated Interconnection Cost": Estimated costs for the Interconnection Facilities, to be designed, engineered and constructed by Company, as provided in Attachment G (Company-Owned Interconnection Facilities).

"Transfer Date": The date, prior to the In-Service Date, upon which Seller transfers to Company all right, title and interest in and to Company-Owned Interconnection Facilities to the extent, if any, that such facilities were constructed by Seller and/or its contractors.

"Wind Turbine": A generating device powered by the wind that is included in Facility.

ARTICLE 1
PARALLEL OPERATION

Company agrees to allow Seller to interconnect and operate the Facility to provide As-Available Energy in parallel with the Company System provided that such interconnection and operation shall not: (i) adversely affect Company's property or the operations of its customers and customers' property; (ii) present safety hazards to the Company System, property or employees or Company's customers or the customers' property or employees; or (iii) otherwise fail to comply with this Agreement. Such parallel operation shall be contingent upon the satisfactory completion, as determined solely by Company, of the Acceptance Test and, to the extent applicable, the Control System Acceptance Test, in accordance with Good Engineering and Operating Practices.

ARTICLE 2

PURCHASE AND SALE OF ENERGY; RATE

FOR PURCHASE AND SALE; BILLING AND PAYMENT

2.1 Purchase and Sale of Actual Output. Seller agrees to deliver to Company all of the Actual Output produced by the Facility and delivered to the Point of Interconnection from the In-Service Date through the end of Term, in accordance with the terms and conditions of this Agreement. Company agrees to purchase electric energy from Seller in accordance with the terms and conditions of this Agreement. Included in the purchase and sale of Actual Output are all of the Environmental Credits associated with the Actual Output. Company will not reimburse Seller for any taxes or fees imposed on Seller including, but not limited to, State of Hawaii general excise tax.

2.2 Payment for Electric Energy. Commencing on the In-Service Date, Seller will be paid for electric energy on a monthly basis as provided in Section 1 (Price for Purchase and Rate of Delivery) of Attachment J (Energy Purchases by Company and Table).

2.3 Payments Prior to the In-Service Date. Prior to the In-Service Date, Seller will be paid for electric energy as follows: the Company shall not be obligated to accept or pay for any electric energy delivered by the Seller, however, any electric energy accepted by the Company during this period shall be paid for at a rate equivalent to 100% of the Contract Price for Contract Year 1.

2.4 Sales of Electric Energy By Company to Seller. Sales of electric energy by Company to Seller shall be governed by an applicable rate schedule filed with the PUC and not by this Agreement.

2.5 Company's Obligation to Provide Certain Data. By the fifth Business Day of each calendar month, Company shall provide Seller or its designated agent with the appropriate data for Seller to compute the amount to be paid for the electric energy in the preceding calendar month as determined in accordance with this Agreement.

2.6 Seller's Preparation of the Monthly Invoice. By the tenth Business Day of each calendar month, Seller shall submit to Company an invoice that separately states the following for the preceding month: (i) the Actual Output during this

period; (ii) the electric energy charge for electric energy purchased by Company as set forth in Attachment J (Energy Purchases by Company and Table) of this Agreement; and (iii) the monthly metering charge as set forth in Article 7 (Seller Payments) of this Agreement.

2.7 Payment Procedures. By the twentieth Business Day of each calendar month (but, except as otherwise provided in the following sentence, no later than the last Business Day of that month if there are less than twenty Business Days in that month), Company shall make payment on such invoice, or provide to Seller an itemized statement of its objections to all or any portion of such invoice and pay any undisputed amount. Notwithstanding the foregoing, the time in which the Company shall make payment to Seller shall be increased on a day for day basis for each Day that Seller is delinquent in providing to the Company the information required under Section 2.6 (Seller's Preparation of the Monthly Invoice)of this Agreement. However, if Company is not timely in providing data required in Section 2.5 (Company's Obligation to Provide Certain Data) and this directly causes Seller to be unable to deliver its invoice in accordance with the timeframe set forth in Section 2.6 (Seller's Preparation of the Monthly Invoice), then Company shall still meet the twentieth Business Day payment date. In such case, an estimated payment, subject to reconciliation with the complete invoice, may be made by Company as an interim provision until a complete invoice can be prepared by Seller and received by Company.

2.8 Late Payments. Notwithstanding all or any portion of such invoice in dispute, any payment not made to Seller by the twentieth Business Day of each calendar month (or the last Business Day of that month if there are less than twenty Business Days in that month), or by the due date for such payment if extended pursuant to Section 2.7 (Payment Procedures), shall accrue interest at the average daily Base Rate at the Bank of Hawaii plus two percent (2%) for the period until the outstanding interest and invoiced amounts (or amounts due to Seller if determined to be less than the invoiced amounts) are paid in full. Partial payments shall be applied first to outstanding interest and then to outstanding invoice amounts.

2.9 Adjustments to Invoices After Payment. In the event adjustments are required to correct inaccuracies in an invoice after payment, the Party requesting adjustment shall recompute and include in the Party's request the amounts due

during the period of the inaccuracy. The difference between the amount paid and that recomputed for the invoice shall either be (i) paid to Seller, or set-off by Company against the next invoice payment to Seller, as appropriate, together with interest from the date that such invoice was payable until the date that such recomputed amount is paid at the average daily Base Rate at the Bank of Hawaii for the period, or (ii) objected to by the Party responsible for such payment within thirty (30) Days following its receipt of such request. All claims for adjustments shall be waived for any deliveries of electricity made more than thirty-six (36) months preceding the date of any such request.

2.10 Company's Billing Records. Seller, after giving reasonable advance written notice to Company, shall have the right to review all billing, metering and other records necessary to verify the accuracy of the data provided by Company pursuant to Section 2.5 (Company's Obligation to Provide Certain Data) and payments relating to the Facility during Company's normal working hours on Business Days. Company shall maintain such records for a period of not less than thirty-six (36) months.

ARTICLE 3
FACILITY OWNED AND/OR OPERATED BY SELLER

3.1 The Facility. Seller agrees to furnish, install, operate, and maintain the Facility in accordance with the provisions of this Agreement, specifically the operating procedures as more fully described in Attachment B (Facility Owned by Seller). After the In-Service Date, Seller agrees that no changes or additions to the Facility shall be made without prior written approval by the Company unless such changes or additions to the Facility could not reasonably be expected to have a material effect on the assumptions used in performing the IRS.

3.2 Allowed Capacity. The net instantaneous MW output from Facility may not exceed the Allowed Capacity. Company may take appropriate action to limit the Allowed Capacity pursuant to, but not limited to, Article 8 (Continuity of Service), Article 9 (Personnel and System Safety), Article 25 (Good Engineering and Operating Practices), Attachment B (Facility Owned by Seller), Attachment J (Energy Purchases by Company and Table) of this Agreement.

3.3 Point of Interconnection. The Point of Interconnection is shown on Attachment E (Three-Line Drawing), as provided in

Section 1(A) (Three-Line Diagram, Relay List, Relay Settings and Trip Scheme) of Attachment B (Facility Owned by Seller). The Point of Interconnection will be at the voltage level of the Company System. If it is necessary to step up the voltage at which Seller's electric energy is delivered to Company System, the Point of Interconnection will be on the high voltage side of the step-up transformer.

ARTICLE 4
COMPANY-OWNED INTERCONNECTION FACILITIES

The terms and conditions related to the Company-Owned Interconnection Facilities are set forth in Attachment G (Company-Owned Interconnection Facilities) of this Agreement.

ARTICLE 5
SCHEDULING

5.1 Seller's Weekly Maintenance Schedule: On Friday of each week, Seller shall provide to Company in writing a projection of maintenance outages for the next seven-Day period. During any such maintenance outage, Seller will provide an update each Day to Company's operating personnel of the status of the maintenance.

5.2 Seller's Annual Maintenance Schedule: In addition, Seller shall submit a schedule of maintenance outages which will reduce the capacity of the Facility by (i) five(5) MW or more for Oahu and (ii) one (1) MW or more for each of Maui and Hawaii for the next two-year period beginning with January of the following year in writing to Company each year by June 30. The schedule shall state the proposed dates and durations of scheduled maintenance, including the scope of work for the maintenance requiring shutdown or reduction in output of the Facility. Company shall review the maintenance schedule for the two-year period and inform Seller in writing no later than December 1 of the same year of Company's concurrence or requested revisions, provided that Seller shall not be required to agree to any proposed revisions that, in Seller's judgment, will void or violate any warranties of equipment that is part of, or used in connection with, the Facility or violate any long-term service agreement with respect to such equipment, in which case Seller shall promptly notify Company thereof, and Seller and Company shall endeavor to reach a mutually satisfactory resolution of the matter in question. With respect to such agreed upon revisions, Seller shall revise its schedule for timing and duration of scheduled shutdowns

and scheduled reductions of output of the Facility to accommodate Company's revisions, unless such revisions would not be consistent with Good Engineering and Operating Practices, and make all commercially reasonable efforts, consistent with Good Engineering and Operating Practices, to accommodate any subsequent changes in such schedule reasonably requested by Company.

5.3 Seller's Notification Obligations. When Seller learns that any of its equipment will be taken out of service or will be returned to service which may effect its delivery of electric energy to Company, Seller shall notify Company as soon as practicable, and in any event, no later than the daily forecasts required by Section 5.1 (Seller's Weekly Maintenance Schedule). This requirement to notify shall include, but not be limited to, notice to Company of Seller's intention to start up or shut down any turbines, such as a high wind-speed shut-down. Any turbine start-up or shut-down shall be coordinated with Company in advance to the extent practicable to allow a reasonable amount of time for Company to make generation adjustments required by the additional energy resulting from a turbine start-up or the loss of energy from a turbine shut-down.

ARTICLE 6
FORECASTING

6.1 Annual Forecasts. For Company's planning purposes, Seller shall, by December 1 of each year during the Term of the Agreement, provide a forecast of each month's average-Day electric energy production from the Facility, by hour, for the following calendar year (or partial calendar year, if the Term does not end on December 31). This forecast (i) shall include an expected range of uncertainty based on historical operating experience, and (ii) shall be updated on a monthly basis by notice given to Company at least six Business Days before the first Business Day of each month.

6.2 Weekly Forecasts. By 0900 Hawaii time on Sunday of the week on which electric energy from the Facility is to be delivered, Seller shall provide Company with an hourly forecast of deliveries for each hour of the day for the ensuing week (Monday to Sunday). Seller shall update a forecast any time information becomes available indicating a change in the forecast of generation of Actual Output from the then current forecast; provided, however, that Seller shall not be required to update such forecasts more frequently than once per hour.

6.3 Data. In connection with the Annual Forecasts and Weekly Forecasts set forth in this Article 6 (Forecasting), Seller shall also provide to Company the data and information required by Company to conduct its own annual and weekly forecasts for all variable generation facilities on the Company System.

6.4 Equipment. In order to make Seller's forecasts as accurate as possible, Seller will install and maintain appropriate equipment for the purpose of forecasting (*e.g.*, for wind projects, instrumentation to measure and record wind speed and direction; for PV projects, instrumentation to measure and record solar radiation).

6.5 Good Faith Estimates. The forecasts called for by this Agreement shall be non-binding, good faith estimates only, and shall be substantially in the form reasonably requested by Company. For Wind projects, Seller shall prepare such forecasts and updates by utilizing a wind speed and direction prediction model or service that is (i) commercially available or proprietary to Seller, and (ii) comparable in accuracy to models or services commonly used in the wind electric energy industry and that reflect turbine availability, so long as such model or service is available at a commercially reasonable cost and is satisfactory to Company in the exercise of its reasonable discretion.

ARTICLE 7
SELLER PAYMENTS

Seller shall pay to Company (i) all amounts pursuant to Attachment G (Company Owned Interconnection Facilities), and (ii) a monthly metering charge of $25.00 per month, which is in addition to any charges due Company pursuant to the applicable rate schedule pursuant to Section 2.4 (Sales of Electric Energy By Company to Seller)of this Agreement.

ARTICLE 8
CONTINUITY OF SERVICE

8.1 General. Company may require Seller to temporarily curtail, interrupt or reduce deliveries of electric energy when necessary in order for Company to construct, install, maintain, repair, replace, remove, investigate, test or inspect any of its equipment or any part of the Company System including, but not limited to, accommodating the installation and/or acceptance test of non-utility owned

facilities to Company System; or if Company determines that such curtailment, interruption or reduction is necessary because of a system emergency, Forced Outage, operating conditions on the Company System such as, but not limited to, those described in Attachment B (Facility Owned by Seller); or the inability to accept deliveries of electric energy due to light loading conditions (such conditions are described in Section 8.5 (Light Loading Conditions)); or if either the Facility does not operate in compliance with Good Engineering and Operating Practices or acceptance of electric energy from Seller by Company would require Company to operate the Company System outside of Good Engineering and Operating Practices, which in this case shall include, but not be limited to, excessive system frequency fluctuations or excessive voltage deviations, and any situation that the Company System Operator determines, at his or her sole discretion using Good Engineering and Operating Practices, could place in jeopardy the reliability of the Company System. In the event that Company initiates a Curtailment Event pursuant to this Section 8.1 (General), Company shall not be obligated to accept or pay for any electric energy from Seller except for such electric energy that Company notifies Seller that it is able to take during the duration of a Curtailment Event.

8.2 Negative Avoided Cost. Company shall not be required to purchase electric energy during any period during which, due to operational circumstances, purchases from Seller will result in costs greater than those which Company would incur if it did not make those purchases, but instead generated an equivalent amount of electric energy itself. Company shall provide Seller with at least twenty-four (24) hours advance oral or written notice of any such period to allow Seller to cease the delivery of electric energy to Company. Company and Seller will work to develop a mutually acceptable format for this notice, including, but not limited to, a listing of typical parameters that define anticipated constraints in purchases from Seller. If Company fails to provide such notice, it will pay the same rate for such purchase of electric energy as would be required had the period not occurred. Company and Seller acknowledge that this Section 8.2 (Negative Avoided Cost) is based upon 18 CFR § 292.304(f) of the Regulations under PURPA issued by the Federal Energy Regulatory Commission and § 6-74-24 of the Standards for Small Power Production and Cogeneration issued by the PUC.

8.3 No Curtailment for Economic Dispatch. This Article 8 (Continuity of Service) of this Agreement is not intended to permit Company to require Seller to curtail, interrupt or reduce deliveries of electric energy based on Company's economic dispatch (for example, as a consequence of Company's filed Avoided Energy Cost Data being lower than the applicable price per MWh paid to Seller under this Agreement, or to make purchases of less expensive electric energy from a Qualifying Facility).

8.4 Reasonable Steps. Company shall take all reasonable steps (such as reducing the output of Base Load Units, including its own Base Load Units, during light loading conditions, taking into consideration factors such as the need to maintain the reliability and stability of the Company System under changing system conditions and configurations, the need for downward regulating reserves, the terms and conditions of power purchase agreements for firm capacity Base Load Units or scheduled electric energy, and the normal minimum loading levels of such units) to minimize the number and duration of curtailments, interruptions or reductions, subject to and in accordance with Attachment B (Facility Owned by Seller).

8.5 Light Loading Conditions. For purposes of this Article 8 (Continuity of Service), as of the Execution Date, light loading conditions typically occur between the hours of 12:00 midnight and 7:00 a.m., but the timing of such conditions may change over time.

ARTICLE 9
PERSONNEL AND SYSTEM SAFETY

Notwithstanding any other provisions of this Agreement, if at any time Company reasonably determines that the Facility may endanger Company's personnel, and/or the continued operation of the Facility may endanger the integrity of the Company System or have an adverse effect on Company's other customers' electric service, Company shall have the right to curtail or disconnect, as determined in the sole discretion of the Company System Operator, Facility from the Company System. The Facility shall remain curtailed or disconnected, as the case may be, until such time as Company is satisfied that the condition(s) referred to above have been corrected, and Company shall not be obligated to accept or pay for any electric energy from Seller except for such electric energy as is accepted by Company from Seller during such period. If Company curtails or disconnects the Facility from the Company System for personnel or system safety reasons, it shall as soon as

practicable notify Seller by telephone and thereafter confirm in writing the reasons for the curtailment or disconnection. In the event that Company initiates a Curtailment Event pursuant to this Article 9 (Personnel and System Safety), Company shall not be obligated to accept or pay for any electric energy from Seller except for such electric energy that Company notifies Seller that it is able to take during the duration of a Curtailment Event.

ARTICLE 10
METERING

10.1 Meters. Company shall purchase and own revenue meters suitable for measuring the Actual Output of the Facility sold to Company in kilowatts and kilowatthours on a time-of-day basis and of reactive power flow in kilovars and true root mean square kilovarhours. The metering point shall be at the Point of Interconnection. Seller shall supply, at no expense to Company, a mutually agreeable location and mounting structure for revenue meters and metering equipment. Company will calibrate the revenue meters in accordance with the latest edition of the American National Standards Institute (ANSI) Code for Electricity Metering. All revenue meters shall be ratcheted to prevent reversal. Company shall install, maintain and annually test such revenue meters and shall be reimbursed by Seller for all reasonably incurred costs for such installation, maintenance and testing work.

10.2 Meter Testing. Company shall provide at least twenty-four (24) hours' notice to Seller prior to any test it may perform on the revenue meters or metering equipment. Seller shall have the right to have a representative present during each such test. Seller may request, and Company shall perform if requested, tests in addition to the annual test and Seller shall pay the cost of such tests. Company may, at its own discretion, perform tests in addition to the annual test and Company shall pay the cost of such tests. If any of the revenue meters or metering equipment is found to be inaccurate at any time, as determined by testing in accordance with this Section 10.2 (Meter Testing), Company shall promptly cause such equipment to be made accurate, and the period of inaccuracy, as well as an estimate for correct meter readings, shall be determined in accordance with Section 10.3 (Corrections).

10.3 Corrections. If any test of revenue meters or metering equipment conducted by Company indicates that the revenue meter readings are in error by one percent (1%) or more, the

revenue meters or meter readings shall be corrected as follows: (i) determine the error by testing the revenue meter at approximately ten percent (10%) of the rated current (test amperes) specified for such revenue meter; (ii) determine the error by testing the revenue meter at approximately one hundred percent (100%) of the rated current (test amperes) specified for the revenue meter; (iii) the average meter error shall then be computed as the sum of one-fifth (1/5) the error determined in the foregoing clause "(i)" and four-fifths (4/5) the error determined in the foregoing clause "(ii)". The average meter error shall be used to adjust the invoices in accordance with Section 2.9 (Adjustment to Invoices After Payment) for the amount of electric energy supplied to Company for the previous six (6) months from Facility, unless records of Company conclusively establish that such error existed for a greater or lesser period, in which case the correction shall cover such actual period of error.

ARTICLE 11
PERMITS AND LAND RIGHTS

11.1 Seller shall obtain, at its expense, any and all Permits required for the construction and operation of the Facility, including but not limited to Land Rights. Seller shall install, operate and maintain the Facility safely and in compliance with all applicable Laws. To the extent private land or land owned by a Governmental Authority is involved, Seller shall obtain, at its expense, any necessary Permits and Land Rights required in order that the Facility can be interconnected with the Company System.

11.2 If the Site is not owned by Seller, a copy of the agreement with the owner of the land which establishes the right of Seller to put the Facility on the Site, together with all required Land Rights, shall be provided to Company before the In-Service Date.

11.3 Seller shall, prior to commencement of construction of Company-Owned Interconnection Facilities (whether to be built by Seller or by Company), provide the necessary Government Approvals and Land Rights for construction, ownership, operation and maintenance of Company-Owned Interconnection Facilities.

ARTICLE 12
TERM OF AGREEMENT

12.1 Initial Term. The initial Term of this Agreement shall commence upon the Execution Date of this Agreement and shall remain in effect for twenty (20) Contract Years following the In-Service Date (the "Initial Term") unless terminated sooner as provided in this Agreement.

12.2 Extended Term. Upon expiration of the Initial Term, Seller shall offer to sell its electric energy to the Company during the Extended Term at the modified electric energy payment rate set forth in Schedule FIT Tier 3, to be determined and approved by the PUC. The Company does not have an obligation to purchase electric energy from the Seller after the Initial Term, however, if the Company does, in its sole discretion, exercise its option to purchase electric energy from Seller during the Extended Term, it will notify Seller no less than six months prior to the expiration of the Initial Term. Either Company or Seller may terminate this Agreement at any time after the end of the Initial Term upon not less than ninety (90) Days' advance written notice to the other Party.

12.3 Termination Rights. Notwithstanding any of the foregoing, Company or Seller may terminate the Agreement at any time upon the occurrence of any condition described in Article 15 (Events of Default).

ARTICLE 13
CONSTRUCTION MILESTONES INCLUDING THE GUARANTEED IN-SERVICE DATE

13.1 Time is of the Essence. Time is of the essence of this Agreement, and Seller's ability to achieve the Construction Milestones is critically important.

13.2 Failure to Meet Certain Reporting Milestones. If Seller misses the Permit Application Filing Date Milestone, the Construction Financing Closing Milestone or the Construction Start Date Milestone as set forth in Attachment L (Reporting Milestones), by more than ninety (90) Days, Seller shall submit to Company, within ten (10) Business Days of an such missed Reporting Milestone, a remedial action plan which shall provide a detailed description of Seller's course of action and plan to achieve the missed Reporting Milestone and all subsequent Construction Milestones, provided that delivery of any remedial action plan shall not relieve Seller of its obligation to meet any subsequent Construction Milestones.

13.3 Guaranteed In-Service Date. Seller shall achieve the In-Service Date no later than the Guaranteed In-Service Date. If Seller fails to achieve the In-Service Date by the Guaranteed In-Service Date, Seller shall have the following grace periods within which to achieve the In-Service Date:

(A) if the failure to achieve the In-Service Date by the Guaranteed In-Service Date is not the result of Force Majeure, Seller shall be entitled to a grace period following the Guaranteed In-Service Date equal to the lesser of 90 Days or the number of Days reasonably necessary to cure the failure in question if such cure were to be implemented promptly and pursued with reasonable diligence; or

(B) if the failure to achieve the In-Service Date by the Guaranteed In-Service Date is the result of Force Majeure, and if and so long as the conditions set forth in Section 21.3 (Satisfaction of Certain Conditions) are satisfied, Seller shall be entitled to a grace period following the Guaranteed In-Service Date equal to the lesser of 180 Days or the duration of the Force Majeure.

13.4 Termination. If the In-Service Date has not been achieved prior to the end of whichever of the two Section 13.3 (Guaranteed In-Service Date) grace periods is applicable, Company shall have the right, notwithstanding any other provision of this Agreement to the contrary, to terminate this Agreement with immediate effect by issuing a written termination notice to Seller designating the Day such termination is to be effective, which Day shall be no later than thirty (30) Days after such notice is deemed to be received by Seller.

13.5 Monthly Progress Reports. Commencing upon the Execution Date of this Agreement, Seller shall submit to Company, on the first Day of each calendar month until the In-Service Date is achieved, progress reports in a form reasonably satisfactory to Company. These progress reports shall notify Company of the current status of each Construction Milestone. Seller shall include in such report a list of all letters, notices, applications, filings and Permits sent to or received from any Governmental Authority and shall provide any such documents as may be reasonably requested by Company. In addition, Seller shall advise Company as soon as reasonably practicable of any problems or issues of which it is aware which may materially impact its ability to meet the Construction Milestones. Seller shall provide Company

with any requested documentation to support the achievement of Construction Milestones within ten (10) Business Days of receipt of such request from Company. Upon the occurrence of a Force Majeure, Seller shall also comply with the requirements of Section 21.3 (Satisfaction of Certain Conditions) to the extent such requirements provide for communications to Company beyond those required under this Section 13.5 (Monthly Progress Reports).

ARTICLE 14
CREDIT ASSURANCE AND SECURITY

14.1 General. Seller is required to post and maintain the Operating Period Security based on the requirements of this Article 14 (Credit Assurance and Security).

14.2 Reservation Fee. To guarantee its undertaking to meet the Guaranteed In-Service Date, Seller shall provide Reservation Fee to Company in accordance with Schedule FIT Tier 3.

14.3 Refund of Reservation Fee. The Reservation Fee may be refunded to Seller under certain circumstances pursuant to the terms of the Schedule FIT Tier 3.

14.4 Amount of the Operating Period Security. To guarantee the performance of Seller's obligations under the Agreement for the period starting from the In-Service Date to the expiration or termination of this Agreement, Seller shall provide Operating Period Security to Company in the amount of $40/kW based on the Contract Capacity. Seller shall fully fund the Operating Period Security prior to the In-Service Date.

14.5 Form of Security. Seller may supply the Operating Period Security required in the form of cash or an irrevocable letter of credit substantially in the form attached to this Agreement as Attachment M (Form of Letter of Credit) from a bank or other financial institution with a credit rating of "A-" or better. If the rating (as measured by Standard & Poors) of the bank or financial institution issuing the irrevocable letter of credit falls below A-, Company may require Seller to replace the irrevocable letter of credit with an irrevocable letter of credit from another bank or financial institution with a credit rating of "A-" or better. If security in the form of an irrevocable letter of credit is utilized by Seller, such security shall be issued for a minimum term of one (1) year. Furthermore, at the end of each year the security shall be renewed for an additional

one (1) year term so that at the time of such renewal, the remaining term of any such security shall not be less than one (1) year. Security in the form of an irrevocable letter of credit shall be consistent with this Agreement and include a provision for at least thirty (30) Days advance notice to Company of any expiration or earlier termination of the security so as to allow Company sufficient time to exercise its rights under said security if Seller fails to extend or replace the security.

14.6 Operating Period Security. The Operating Period Security established, funded, and maintained by Seller pursuant to the provisions of this Article 14 (Credit Assurance and Security) shall be available to pay any amount due Company pursuant to this Agreement, and to provide Company security that Seller will construct the Facility to meet the Construction Milestones. The Operating Period Security shall also provide security to Company to cover damages, should the Seller fail operate the Facility in accordance with this Agreement. Seller shall maintain the Operating Period Security at the contractually-required level throughout the Term of this Agreement. Seller shall replenish the Operating Period Security to such required level within fifteen (15) Business Days after any draw on the Operating Period Security by Company.

14.7 Company's Right to Draw from Operating Period Security. In addition to any other remedy available to it, Company may, before or after termination of this Agreement, draw from the Operating Period Security such amounts as are necessary to recover amounts Company is owed pursuant to this Agreement, including, but without limitation, any damages due Company and any amounts for which Company is entitled to indemnification under this Agreement. Company may, in its sole discretion, draw all or any part of such amounts due Company from any form of security to the extent available pursuant to this Article 14 (Credit Assurance and Security), and from all such forms, and in any sequence Company may select. Any failure to draw upon the Operating Period Security or other security for any damages or other amounts due Company shall not prejudice Company's rights to recover such damages or amounts in any other manner.

14.8 Establishment of Operating Period Security. The Operating Period Security shall be maintained at Seller's expense, and shall be originated by or deposited in a financial institution or company ("Issuer") acceptable to Company. Seller may change the form of the Operating Period Security

at any time and from time to time upon reasonable prior notice to Company, but the Operating Period Security shall at all times be comprised of one or a combination of the forms specified above in Section 14.5 (Form of Security).

14.9 Certain Requirements. The form of such security shall meet Company's requirements to ensure that claims or draw-downs can be made unilaterally by Company in accordance with the terms of this Agreement. If the security is not renewed or extended as required herein, Company shall have the right to draw immediately upon the security and to place the amounts so drawn, at Seller's cost and with Seller's funds, in an interest bearing escrow account in accordance with Section 14.10 (Security in the Form of Cash), until and unless Seller provides a substitute form of such security meeting the requirements of this Article 14 (Credit Assurances and Security). In all cases, the reasonable costs and expenses of establishing, renewing, substituting, canceling, increasing, reducing, or otherwise administering the Letter of Credit shall be borne by Seller.

14.10 Security in the Form of Cash. If the security is in the form of cash as permitted in Section 14.5 (Form of Security), above, the cash shall be United States currency, in which Company holds a first and exclusive perfected security interest, deposited with a reputable, federally-insured bank, either: (i) in an account under which Company is designated as beneficiary with sole authority to draw from the account or otherwise access the security; or (ii) held by Issuer as escrow agent with instructions to pay claims made by Company pursuant to this Agreement, such instructions to be in a form satisfactory to Company. Seller, Issuer (or escrow) and Company shall execute a control agreement and other agreements required by Company in form and content satisfactory to Company to perfect Company's security interest in the Operating Period Security. Security provided in the form of cash shall include a requirement for immediate notice to Company from Issuer and Seller in the event that the sums held as security in the account or trust do not at any time meet the required level for the Operating Period Security as set forth in this Article 14 (Credit Assurance and Security). Funds held in the account may be deposited in a money-market fund, short-term treasury obligations, investment-grade commercial paper and other liquid investment-grade investments with maturities of three months or less, with all investment income thereon to be taxable to, and to

accrue for the benefit of, Seller. After the In-Service Date is achieved, annual account sweeps for recovery of interest earned by the Operating Period Security shall be allowed by Seller. At such times as the balance in the escrow account exceeds the amount of Seller's obligation to provide security hereunder, Company shall remit to Seller on demand any excess in the escrow account above Seller's obligations, including, but not limited to, any and all damages owed by Seller to Company under the terms of this Agreement.

14.11 Release of Operating Period Security. Promptly following the end of the Term, and the completion of all of Seller's obligations, including, but not limited to, the obligation to pay any and all damages owed by Seller to Company, under this Agreement, Company shall release the Operating Period Security (including any accumulated interest, if applicable) to Seller.

ARTICLE 15
EVENTS OF DEFAULT

15.1 Events of Default by Seller. The occurrence of any of the following shall constitute an Event of Default by Seller:

(A) if at any time during the Term, Seller delivers or attempts to deliver to the Point of Interconnection for sale under this Agreement electric energy that was not generated by the Facility;

(B) if at any time subsequent to the In-Service Date, Seller fails to provide electric energy to Company for a period of three hundred sixty-five (365) or more consecutive Days, unless such failure is caused by the inability of Company to accept such electric energy;

(C) failure by Seller to deliver from the Facility at least sixty percent (60%) of the Annual Contract Energy to the Point of Interconnection for a period of three consecutive Contract Years;

(D) if at any time during the Term, Seller fails to satisfy the Credit Assurance and Security requirements agreed to pursuant to Article 14 (Credit Assurance and Security) of this Agreement;

(E) if at any time subsequent to the In-Service Date, Seller fails to install, operate, maintain, or repair the

Facility in accordance with Good Engineering and Operating Practices if such failure is not cured without thirty (30) Days after written notice of such failure from Company unless such failure cannot be cured within said thirty (30) Day period and Seller is making commercially reasonable efforts to cure such failure, in which case Seller shall have a cure period of 365 Days after Company's written notice of such failure.

15.2 Events of Default by a Party. The occurrence of any of the following during the Term of the Agreement shall constitute an Event of Default by the Party responsible for the failure, action or breach in question:

(A) The failure to make any payments required pursuant to this Agreement when due if such failure is not cured within ten (10) Business Days after written notice is received by the Party failing to make such payment;

(B) Any representation or warranty made by such Party herein is false and misleading in any material respect when made;

(C) Such Party becomes bankrupt;

(D) Such Party fails to comply with an arbitrator's decision under Article 28 (Dispute Resolution), or on Independent Evaluator's decision under Article 23 (Process for Addressing Revisions to Performance Standards), within thirty (30) Days after such decision becomes binding on the Parties in accordance with Article 28 (Dispute Resolution) or within thirty (30) Days of the issuance of such decision under Article 23 (Process for Addressing Revisions to Performance Standards), as applicable, or, if such decision cannot be complied with within thirty (30) Days, such Party fails to have commenced commercially reasonable efforts designed to comply and diligently continued such commercially reasonable efforts until compliance is attained; or

(E) A Party, by act or omission, materially breaches or defaults on any material covenant, condition or other provision of this Agreement, other than the provisions specified in Section 15.1 (Events of Default by Seller) and Section 15.2(A) through Section 15.2(D), if such breach or default is not cured within thirty (30) Days after written notice of such breach or default from the other Party unless such breach or default cannot be

cured within said thirty (30) Day period and the Non-performing Party is making commercially reasonable efforts to cure such breach or default, in which case the Non-performing Party shall have a cure period of 365 Days of Company's written notice of such breach or default.

15.3 Cure/Grace Periods. Before becoming an Event of Default, the occurrences set forth in Section 15.1 (Events of Default by Seller) and Section 15.2 (Events of Default by a Party) are subject to the following cure/grace periods:

(A) If the occurrence is not the result of Force Majeure, Non-performing Party shall be entitled to a cure period to the limited extent expressly set forth in the applicable provision of Section 15.1 (Events of Default by Seller) or Section 15.2(Events of Default by a Party); or

(B) If the occurrence is the result of Force Majeure, and if and so long as the conditions set forth in Section 21.3 (Satisfaction of Certain Conditions) are satisfied, the Non-performing Party shall be entitled to a grace period as provided in Section 21.5 (Events of Default), which shall apply in lieu of any cure periods provided in Section 15.1 (Events of Default by Seller) and Section 15.2(Events of Default by a Party).

15.4 Rights of the Non-defaulting Party. If an Event of Default shall have occurred and be continuing, the Party who is not the Defaulting Party ("Non-defaulting Party") shall have the right (i) to terminate this Agreement by sending written notice to the Defaulting Party as provided in this Section 15.4 (Rights of the Non-defaulting Party); (ii) to withhold any payments due to the Defaulting Party under this Agreement; (iii) suspend performance; and (iv) exercise any other right or remedy available at law or in equity to the extent permitted under this Agreement. A notice terminating this Agreement pursuant to this Section 15.4 (Rights of the Non-defaulting Party) shall designate the Day such termination is to be effective which Day shall be no later than thirty (30) Days after such notice is deemed to be received by the Defaulting Party and not earlier than the first to occur of the Day such notice is deemed to be received by the Defaulting Party or the Day following the expiration of any period afforded the Defaulting Party under Section 15.1 (Events of Default by Seller) and Section 15.2 (Events of Default by a Party) to cure the default in

question. If the Agreement is terminated by Company because of one or more of the Events of Default by Seller, Company shall have the right, in addition to the rights set forth above in this Section 15.4(Rights of the Non-defaulting Party), to collect liquidated damages ("Termination Damages"), which shall be calculated in accordance with Article 16 (Damages in the Event of Termination by the Company).

15.5 Force Majeure. To the extent a Non-performing Party is entitled to defer certain liabilities pursuant to Article 21 (Force Majeure) of the Agreement, the permitted period of deferral shall be governed by Section 21.5 in lieu of this Article 15 (Events of Default).

15.6 In-Service Date. Not withstanding any other provision of this Article 15 (Events of Default) to the contrary, any failure of Seller to achieve the In-Service Date by the Guaranteed In-Service Date shall be governed by Article 13 (Construction Milestones Including the Guaranteed In-Service Date) in lieu of this Article 15 (Events of Default).

15.7 Remedies. Seller acknowledges that Company is a public utility and is relying upon Seller's performance of its obligations under this Agreement, and that Company and/or its customers may suffer irreparable injury as a result of any failure in Seller's performance of such obligations. Accordingly, the Termination Damages shall not limit or otherwise affect Company's rights and remedies for Seller's failure to perform its obligations under this Agreement when such failure does not result in a termination of this Agreement, including but not limited to Company's right to damages arising out of such failure in performance and Company's right to seek specific performance.

ARTICLE 16
DAMAGES IN THE EVENT OF TERMINATION BY COMPANY

16.1 Termination Due to Failure to Meet the Guaranteed In-Service Date. If the Agreement is terminated by Company pursuant to Section 13.4 (Termination), Company shall be entitled to retain the Reservation Fee pursuant to the Schedule FIT Tier 3.

16.2 Termination Due to an Event of Default. If the Agreement is terminated by Company in accordance with this Agreement after the In-Service Date due to an Event of Default where Seller is the Defaulting Party, Company shall be entitled to

Termination Damages calculated by multiplying the Contract Capacity by $40/kW.

16.3 Liquidated Damages Appropriate. Each Party agrees and acknowledges that (i) the damages that Company would incur due to early termination of the Agreement pursuant to either Section 13.4 (Termination) or Section 15.4 (Rights of the Non-defaulting Party) would be difficult or impossible to calculate with certainty, (ii) the Reservation Fee and the Termination Damages, as applicable, are an appropriate approximation of such damages, and (iii) payment of Termination Damages or the retention of the Reservation Fee does not relieve Seller of liability for costs and balances incurred prior to the effective date of such termination.

ARTICLE 17
INDEMNIFICATION

17.1 Indemnification of Company.

(A) Personal Injury, Death or Property Damage. Seller shall indemnify, defend, and hold harmless Company, its successors, permitted assigns, affiliates, controlling persons, directors, officers, employees, servants and agents, including but not limited to contractors and their employees (collectively referred to as an "Indemnified Company Party"), from and against any Losses suffered, incurred or sustained by any Indemnified Company Party or to which any Indemnified Company Party becomes subject, resulting from, arising out of or relating to any Claim by a third party not controlled by or under common ownership and/or control with Company (whether or not well founded, meritorious or unmeritorious)relating to any actual or alleged personal injury or death or damage to property, in any way arising out of, incident to, or resulting directly or indirectly from the acts or omissions of Seller or its agents or subcontractors, except to the extent that any of the foregoing is attributable to the gross negligence or willful misconduct of an Indemnified Company Party.

(B) Compliance with Laws. Any Losses incurred by an Indemnified Seller Party for noncompliance by Seller or an Indemnified Seller Party with applicable Laws shall not be reimbursed by Company but shall be the sole responsibility of Seller. Seller shall indemnify, defend and hold harmless each Indemnified Company Party

from and against any and all Losses in any way arising out of, incident to, or resulting directly or indirectly from the failure of Seller to comply with any Laws.

(C) Notice. If Seller shall obtain knowledge of any Claim subject to Section 17.1(A) (Personal Injury, Death or Property Damage), Section 17.1(B) (Compliance with Laws) or otherwise under this Agreement, Seller shall give prompt notice thereof to Company, and if Company shall obtain any such knowledge, Company shall give prompt notice thereof to Seller.

(D) Indemnification Procedures.

(1) In case any Claim subject to Section 17.1(A) (Personal Injury, Death or Property Damage) or Section 17.1(B) (Compliance with Laws) or otherwise under this Agreement, shall be brought against an Indemnified Company Party, Company shall notify Seller of the commencement thereof and, provided that Seller has acknowledged in writing to Company its obligation to an Indemnified Company Party under this Section 17.1 (Indemnification of Company), Seller shall be entitled, at its own expense, acting through counsel acceptable to Company, to participate in and, to the extent that Seller desires, to assume and control the defense thereof, provided that Seller shall not compromise or settle a Claim against an Indemnified Company Party without the prior written consent of Company which consent shall not be unreasonably withheld.

(2) Seller shall not be entitled to assume and control the defense of any such Claim subject to Section 17.1(A) (Personal Injury, Death or Property Damage), Section 17.1(B) (Compliance with Laws) or otherwise under this Agreement, if and to the extent that, in the opinion of Company, such Claim involves the potential imposition of criminal liability on an Indemnified Company Party or a conflict of interest between an Indemnified Company Party and Seller, in which case Company shall be entitled, at its own expense, acting through counsel acceptable to Seller to participate in any Claim, the defense of which has been assumed by Seller. Company shall supply Seller with such information and documents

requested by Seller as are necessary or advisable for Seller to possess in connection with its participation in any Claim to the extent permitted by this Section 17.1(2). An Indemnified Company Party shall not enter into any settlement or other compromise with respect to any Claim without the prior written consent of Seller, which consent shall not be unreasonably withheld or delayed.

(3) Upon payment of any Losses by Seller pursuant to this Section 17.1 (Indemnification of Company) or other similar indemnity provisions contained herein to or on behalf of Company, Seller, without any further action, shall be subrogated to any and all claims that an Indemnified Company Party may have relating thereto.

(4) Company shall fully cooperate and cause all Company Indemnified Parties to fully cooperate, in the defense of or response to any Claim subject to Section 17.1 (Indemnification of Company).

17.2 Indemnification of Seller.

(A) Personal Injury, Death or Property Damage. Company shall indemnify, defend, and hold harmless Seller, its successors, permitted assigns, affiliates, controlling persons, directors, officers, employees, servants and agents, including but not limited to contractors and their employees (collectively referred to as an "Indemnified Seller Party"), from and against any Losses suffered, incurred or sustained by any Indemnified Seller Party or to which any Indemnified Seller Party becomes subject, resulting from, arising out of or relating to any Claim by a third party not controlled by or under common ownership and/or control with Company (whether or not well founded, meritorious or unmeritorious)relating to any actual or alleged personal injury or death or damage to property, in any way arising out of, incident to, or resulting directly or indirectly from the acts or omissions of Seller or its agents or subcontractors, except to the extent that any of the foregoing is attributable to the gross negligence or willful misconduct of an Indemnified Seller Party.

(B) Notice. If Company shall obtain knowledge of any Claim subject to Section 17.2(A) (Personal Injury, Death or Property Damage) or otherwise under this Agreement, Company shall give prompt notice thereof to Seller, and if Seller shall obtain any such knowledge, Seller shall give prompt notice thereof to Company.

(1) In case any action, suit or proceeding subject to Section 17.2(A) (Personal Injury, Death or Property Damage), or otherwise under this Agreement, shall be brought against an Indemnified Seller Party, Seller shall notify Company of the commencement thereof and, provided that Company has acknowledged in writing to Seller its obligation to an Indemnified Seller Party under this Section 17.2 (Indemnification of Seller), Company shall be entitled, at its own expense, acting through counsel acceptable to Seller, to participate in and, to the extent that Company desires, to assume and control the defense thereof, provided, however, Company shall not compromise or settle a Claim against an Indemnified Seller Party without the prior written consent of Seller which consent shall not be unreasonably withheld.

(2) Company shall not be entitled to assume and control the defense of any such Claim subject to Section 17.2(A) (Personal Injury, Death or Property Damage), or otherwise under this Agreement, if and to the extent that, in the opinion of Seller, such Claim involves the potential imposition of criminal liability on an Indemnified Seller Party or a conflict of interest between an Indemnified Seller Party and Company, in which case Seller shall be entitled, at its own expense, acting through counsel acceptable to Company, to participate in any Claim the defense of which has been assumed by Company. An Indemnified Seller Party shall supply Company with such information and documents requested by Company as are necessary or advisable for Company to possess in connection with its participation in any Claim, to the extent permitted by this Section 17.2(C)(2). An Indemnified Seller Party shall not enter into any settlement or other compromise with respect to any Claim without the prior written consent of

Company, which consent shall not be unreasonably withheld or delayed.

(3) Upon payment of any Losses by Company pursuant to this Section 17.2 (Indemnification of Seller) or other similar indemnity provisions contained herein to or on behalf of Seller, Company, without any further action, shall be subrogated to any and all claims that an Indemnified Seller Party may have relating thereto.

(4) Seller shall fully cooperate and cause all Seller Indemnified Parties to fully cooperate, in the defense of or response to any Claim subject to Section 17.2 (Indemnification of Seller).

17.3 Seller As An Agency of the State.

Notwithstanding the foregoing, where the Seller is an agency of the State of Hawaii (the "State"), the Parties agree that the indemnification provisions set forth in the Company's Rule No. 14 (Service Connections and Facilities on Customer's Premises), Section H (Interconnection of Distributed Generating Facilities Operating in Parallel with the Company's Electric System), Appendix II (Standard Interconnection Agreement), Section 18 (Indemnification) shall apply and are hereby incorporated by reference into this Agreement.

17.4 Seller As an Agency of The Department of Defense (The "DOD").

Notwithstanding the foregoing, where the Seller is an agency of the Department of Defense (the "DOD"), the Parties agree that the indemnification provisions set forth in the Company's Rule No. 14 (Service Connections and Facilities on Customer's Premises), Section H (Interconnection of Distributed Generating Facilities Operating in Parallel with the Company's Electric System), Appendix II (Standard Interconnection Agreement), Section 18 (Indemnification) shall apply and are hereby incorporated by reference into this Agreement.

ARTICLE 18
INSURANCE

18.1 Insurance. Seller shall, at its own expense and during the Term and during any other time that Facility is interconnected with Company System, secure and maintain in effect with a responsible insurance company authorized to do insurance business in Hawaii the following insurance that will protect Seller and Company: commercial general liability insurance with respect to Facility, Seller's operations, and Seller's interconnection with Company System, with a bodily injury and property damage combined single limit of two million dollars ($2,000,000).

18.2 Insurance Policy Requirements. Said insurance shall include Company as an additional insured, shall include contractual liability coverage for written contracts and agreements including this Agreement, and shall be non-cancelable and non-alterable without thirty (30) Days' prior written notice to Company. "Claims made" policies are not acceptable.

18.3 Annual Review by Company. The coverage limits shall be reviewed annually by Company and if, in Company's discretion, Company determines that the coverage limits should be increased, Company shall so notify Seller. The amount of any increase of the coverage limits, when considered as a percentage of the then existing coverage limits, shall not exceed the cumulative amount of increase in the Consumer Price Index occurring after the coverage limits herein were last set. Seller shall within thirty (30) Days of notice from Company increase the coverage as directed in such notice and the costs of such increased coverage limits shall be borne by Seller.

18.4 Additional Requirements. The insurance required hereunder shall provide that it is primary with respect to Seller and Company. Seller shall provide evidence of such insurance by providing certificates of insurance to Company prior to construction of Company-Owned Interconnection Facilities and within 30 Days of any change and upon renewal of the policy. Seller's indemnity and other obligations shall not be limited by the foregoing insurance requirements. Any deductible shall be the responsibility of Seller. The limits may be obtained through a combination of primary and excess liability policies.

ARTICLE 19
TRANSFERS, ASSIGNMENTS, AND FACILITY DEBT

This Agreement may not be assigned by either the Company or the Seller without the prior written consent of the other Party (such consent not to be unreasonably withheld, conditioned, or delayed); provided that Seller shall have the right, without the consent of the Company, for the purposes of arranging or rearranging debt and/or equity financing for the Facility, to assign all or any part of its rights or benefits, but not its obligations, to any lender providing debt financing for the Facility. Seller shall immediately provide written notice to the Company of any assignment of all or part of this Agreement and Seller shall provide to the Company all information about the assignment and the assignee reasonably requested by the Company.

ARTICLE 20
SALE OF ENERGY TO THIRD PARTIES

Seller shall not sell energy from Facility to any Third Party.

ARTICLE 21
FORCE MAJEURE

21.1 Definition of Force Majeure. The term "Force Majeure", as used in this Agreement, means causes or events beyond the reasonable control of, and without the fault or negligence of the Party claiming Force Majeure, including, without limitation, acts of God, sudden actions of the elements such as floods, earthquakes, hurricanes, or tornadoes, or volcanic activity; high winds of sufficient strength or duration to materially damage a facility or significantly impair its operation for a period of time longer than normally encountered in similar businesses under comparable circumstances; lightning; fire; sabotage; vandalism beyond that which could reasonably be prevented by the Party claiming Force Majeure; terrorism; war; riots; explosion; blockades; insurrection; strike; slow down or labor disruptions (even if such difficulties could be resolved by conceding to the demands of a labor group); and emergency orders issued by a Governmental Authority.

21.2 Exclusions From Force Majeure. Force Majeure does not include:

(A) any acts or omissions of any Third Party, including, without limitation, any vendor, materialman, customer,

or supplier of Seller, unless such acts or omissions are themselves excused by reason of Force Majeure;

(B) any full or partial curtailment in the electric output of Facility that is caused by or arises from a mechanical or equipment breakdown or other mishap or events or conditions attributable to normal wear and tear or defects, unless such mishap is caused by Force Majeure;

(C) changes in market conditions that affect the cost of Seller's supplies, or that affect demand or price for any of Seller's products, or that otherwise render this Agreement uneconomic or unprofitable for Seller;

(D) Seller's inability to obtain Permits or approvals of any type for the construction, operation, or maintenance of Facility;

(E) Seller's inability to obtain sufficient fuel, power or materials to operate its Facility, except if Seller's inability to obtain sufficient fuel, power or materials is caused solely by an event of Force Majeure;

(F) Seller's failure to obtain additional funds, including funds authorized by a state or the federal government or agencies thereof, to supplement the payments made by Company pursuant to this Agreement;

(G) a Forced Outage except where such Forced Outage is caused by an event of Force Majeure;

(H) litigation or administrative or judicial action pertaining to the Agreement, the Site, the Facility, the acquisition, maintenance or renewal of financing or any Permits, or the design, construction, maintenance or operation of the Facility or the Company System; or

(I) any full or partial curtailment in the delivery of the Actual Output of Seller or of the ability of Company to accept Actual Output from Seller which is caused by any Third Party including, without limitation, any vendor or supplier of Seller or Company, except to the extent due to Force Majeure.

21.3 Satisfaction of Certain Conditions. Section 21.4 (In-Service Date), Section 21.5 (Events of Default)and Section 21.6 (Effect of Force Majeure)defer or limit certain

liabilities of a Party for delay and/or failure in performance to the extent such delay or failure is the result of conditions or events of Force Majeure; provided, however, that a Non-performing Party is only entitled to such limitations or deferrals of liabilities as and to the extent the following conditions are satisfied:

(A) the Non-performing Party gives the other Party, within 48 hours after the Force Majeure condition or event begins, written notice stating that Seller considers such condition or event to constitute Force Majeure and describing the particulars of such Force Majeure condition or event;

(B) the Non-performing Party gives the other Party, within 14 Days after the Force Majeure condition or event begins, a written explanation of the Force Majeure condition or event and its effect on the Non-performing Party's performance, which explanation shall include evidence reasonably sufficient to establish that the occurrence constitutes Force Majeure;

(C) the suspension of performance is of no greater scope and of no longer duration than is required by the condition or event of Force Majeure;

(D) the Non-performing Party proceeds with reasonable diligence to remedy its inability to perform and provides written weekly progress reports to the other Party describing actions taken to end the Force Majeure; and

(E) when the condition or event of Force Majeure ends and the Non-performing Party is able to resume performance of its obligations under this Agreement, that Party shall give the other Party written notice to that effect.

21.4 In-Service Date. A condition or event of Force Majeure affecting the achievement of the In-Service Date shall not relieve Seller from Termination Damages for early termination under Section 16.1(Termination Due to Failure to Meet the Guaranteed In-Service Date), although such a condition or event of Force Majeure shall, if and for so long as the conditions of Section 21.3 (Satisfaction of Certain Conditions) are satisfied, have the effect of deferring such liabilities to the extent of the grace period provided in Section 13.3(B).

21.5 Events of Default. If an occurrence that would constitute an Event of Default under Article 15 (Events of Default) is the result of a condition or event of Force Majeure, Seller shall not be relieved from liability for Termination Damages for early termination under Article 16 (Damages in the Event of Termination by Company), although such a condition or event of Force Majeure shall, if and for so long as the conditions set forth in Section 21.3 (Satisfaction of Certain Conditions) are satisfied, have the effect of deferring such liability for the lesser of the duration of the Force Majeure or three hundred sixty-five (365) Days from the occurrence or inception of the Force Majeure, as noticed pursuant to Section 21.3(A) (Satisfaction of Certain Conditions).

21.6 Effect of Force Majeure. Other than as provided in Section 21.4 (In-Service Date) and Section 21.5 (Events of Default), neither Party shall be responsible or liable for any delays or failures in its performance under this Agreement as and to the extent (i) such delays or failures are substantially caused by conditions or events of Force Majeure, and (ii) the conditions of Section 21.3(A) (Satisfaction of Certain Conditions) are satisfied.

21.7 No Relief of Other Obligations. Except as otherwise expressly provided for in this Agreement, the existence of a condition or event of Force Majeure shall not relieve the Parties of their obligations under this Agreement (including, but not limited to, payment obligations) to the extent that performance of such obligations is not precluded by the condition or event of Force Majeure.

21.8 No Extension of the Term. In no event will any delay or failure of performance caused by any conditions or events of Force Majeure extend this Agreement beyond its stated Term.

ARTICLE 22
WARRANTIES AND REPRESENTATIONS

22.1 By the Parties. Both Company and Seller represent and warrant, respectively, that:

(A) Each respective Party has all necessary right, power and authority to execute, deliver and perform this Agreement

(B) The execution, delivery and performance of this Agreement by each respective Party will not result in a violation of any Laws of any Governmental Authority, or

conflict with, or result in a breach of, or cause a default under, any agreement or instrument to which such Party is also a Party or by which it is bound. No consent of any person or entity not a Party to this Agreement, including any Governmental Authority (other than the PUC and other agencies whose approval is necessary for construction of Company-Owned Interconnection Facilities), is required for such execution, delivery and performance by either Party.

22.2 By Seller. Seller represents and warrants that:

(A) It is an entity in good standing with the Hawaii Department of Commerce and Consumer Affairs and shall provide Company with a certified copy of a certificate of good standing by the Execution Date.

(B) As of the In-Service Date, the Facility is a qualified renewable resource under RPS.

ARTICLE 23
PROCESS FOR ADDRESSING REVISIONS TO PERFORMANCE STANDARDS

23.1 Revisions to Performance Standards. The Parties acknowledge that, during the Term, certain Performance Standards may be revised or added to facilitate necessary improvements in integrating intermittent renewable energy resources into the Company System and operations. In particular, the following Performance Standards in Attachment B (Facility Owned by Seller) to this Agreement may be revised: Section 3(C) (Ramp Rates); Section 3(D) (Power Fluctuation Rate); and, Section 3(M) (Frequency Regulation). Such revisions or additions may be attributable to, without limitation, the following: changes in penetration levels of intermittent renewable resources on the Company System, changes to the state of commercially available technology, changes to Company-owned generation resources, changes in customer electrical usage (such as changes in average hourly load profiles), and changes in Laws (e.g., new environmental constraints, which may limit Company's ability to start/stop its generators in response to integration of intermittent generation, or Laws impacting the power quality standards for the Company System).

23.2 Performance Standards Information Request. If Company concludes that a Performance Standards Revision is necessary or important for the operation of the Company System and is

capable of being complied with by Seller, Company shall have the right to issue to Seller a Performance Standards Information Request with respect to such Performance Standards Revision. Seller shall, within a reasonable period of time following Seller's receipt of such Performance Standards Information Request, but in no event more than 90-Days after Seller's receipt of such Request (or such other period of time as Company and Seller may agree in writing), submit to Company a Performance Standards Proposal responsive to the Performance Standards Revision proposed in such Performance Standards Information Request.

23.3 Performance Standards Proposal. Upon receipt of a Performance Standards Proposal submitted in response to a Performance Standards Information Request, Company will evaluate such Performance Standards Proposal and Seller shall assist Company in performing such evaluation as and to the extent reasonably requested by Company (including, but not limited to, providing such additional information as Company may reasonably request and participating in meetings with Company as Company may reasonably request). Company shall have no obligation to evaluate a Performance Standards Proposal submitted at Seller's own initiative.

23.4 Performance Standards Revision Document. If, following Company's evaluation of a Performance Standards Proposal, Company desires to consider implementing the Performance Standards Revision addressed in such Proposal, Company shall provide Seller with written notice to that effect, such notice to be issued to Seller within 180 Days of receipt of the Performance Standards Proposal, and Company and Seller shall proceed to negotiate in good faith a Performance Standards Revision Document setting forth the specific changes to the Agreement that are necessary to implement such Performance Standards Revision. A decision by Company to initiate negotiations with Seller as aforesaid shall not constitute an acceptance by Company of any of the details set forth in Seller's Performance Standards Proposal for the Performance Standards Revision in question, including but not limited to the Performance Standards Modifications and the Performance Standards Pricing Impact. Any adjustment to the Contract Price pursuant to such Performance Standards Revision Document shall be limited to the Performance Standards Pricing Impact (other than with respect to the financial consequences of non-performance as to a Performance Standards Revision). The time periods set forth in such Performance Standards Revision Document as to the

effective date for the Performance Standards Revision shall be measured from the date the PUC Performance Standards Revision Order becomes non-appealable as provided in Section 23.6 (PUC Performance Standards Revision Order).

23.5 Failure to Reach Agreement. If Company and Seller are unable to agree upon and execute a Performance Standards Revision Document within 180 Days of Company's written notice to Seller pursuant to Section 23.4 (Performance Standards Revision Document), Company shall have the option of declaring the failure to reach agreement on and execute such Document to be a dispute and submit such dispute to an Independent Evaluator for the conduct of a determination pursuant to Section 23.10 (Dispute) of this Agreement. Any decision of the Independent Evaluator, rendered as a result of such dispute shall include a form of a Performance Standards Revision Document as described in Section 23.4 (Performance Standards Revision Document).

23.6 PUC Performance Standards Revision Order. No Performance Standards Revision Document shall constitute an amendment to the Agreement unless and until a PUC Performance Standards Revision Order issued with respect to such Document has become non-appealable. Once the condition of the preceding sentence has been satisfied, such Performance Standards Revision Document shall constitute an amendment to this Agreement. To be "non-appealable" under this Section 23.6 (PUC Performance Standards Revision Order), such PUC Performance Standards Revision Order shall be either (i) not subject to appeal to any Circuit Court of the State of Hawaii or the Supreme Court of the State of Hawaii, because the thirty (30) Day period (accounting for weekends and holidays as appropriate) permitted for such an appeal has passed without the filing of notice of such an appeal, or (ii) affirmed on appeal to any Circuit Court of the State of Hawaii or the Supreme Court, or the Intermediate Appellate Court upon assignment by the Supreme Court, of the State of Hawaii, or affirmed upon further appeal or appellate process, and is not subject to further appeal, because the jurisdictional time permitted for such an appeal (and/or further appellate process such as a motion for reconsideration or an application for writ of certiorari) has passed without the filing of notice of such an appeal (or the filing for further appellate process).

23.7 Company's Rights. The rights granted to Company under Section 23.4 (Performance Standards Revision Document) and Section 23.5 (Failure to Reach Agreement) above are

exclusive to Company. Seller shall not have a right to initiate negotiations of a Performance Standards Revision Document or to initiate dispute resolution under Section 23.10 (Dispute), as a result of a failure to agree upon and execute any Performance Standards Revision Document.

23.8 Seller's Obligation. Notwithstanding any provision of this Article 23 (Process for Addressing Revisions to Performance Standards) to the contrary, Seller shall have no obligation to respond to more than one Performance Standards Information Request during any 12-month period.

23.9 Limited Purpose. This Article 23 (Process for Addressing Revisions to Performance Standards) is intended to specifically address necessary revisions to the Performance Standards to enhance integration of intermittent resources onto Company System, or to comply with future Laws which may be driven in part by higher integration of intermittent resources, and is not intended for either Party to provide a means for renegotiating any other terms of this Agreement. Revisions to the Performance Standards in accordance with the provisions of this Article 23 (Process for Addressing Revisions to Performance Standards)are not intended to materially increase Seller's risk of non-performance or default.

23.10 Dispute. If Company decides to declare a dispute as a result of the failure to reach agreement and execute a Performance Standards Revision Document pursuant to Section 23.5 (Failure to Reach Agreement), it shall provide written notice to that effect to Seller. Within 20 Days of delivery of such notice Seller and Company shall agree upon an Independent Evaluator to resolve the dispute regarding a Performance Standards Revision Document. The Independent Evaluator shall be reasonably qualified and expert in renewable energy power generation, matters relating to the Performance Standards, financing, and power purchase agreements. If the Parties are unable to agree upon an Independent Evaluator within such 20-Day period, Company shall apply to the PUC for the appointment of an Independent Evaluator. If an Independent Observer retained under the Competitive Bidding Framework is qualified and willing and available to serve as Independent Evaluator, the PUC shall appoint one of the persons or entities qualified to serve as an Independent Observer to be the Independent Evaluator; if not, the PUC shall appoint another qualified person or entity to serve as Independent Evaluator. In its

application, Company shall ask the PUC to appoint an Independent Evaluator within 30 Days of the application.

(A) Promptly upon appointment, the Independent Evaluator shall request the Parties to address the following matters within the next 15 Days:

(1) The Performance Standard Revision(s);

(2) The technical feasibility of complying with the Performance Standard Revision(s)and likelihood of compliance;

(3) How Seller would comply with the Performance Standard Revision(s);

(4) Reasonably expected net costs and/or lost revenues associated with the Performance Standards Revision(s);

(5) The appropriate level, if any, of Performance Standards Pricing Impact in light of the foregoing; and

(6) Contractual consequences for non-performance that are commercially reasonable under the circumstances.

(B) Within 90 Days of appointment, the Independent Evaluator shall render a decision unless the Independent Evaluator determines it needs to have additional time, not to exceed 45 Days, to render a decision.

(C) The Parties shall assist the Independent Evaluator throughout the process of preparing its review, including making key personnel and records available to the Independent Evaluator, but neither Party shall be entitled to participate in any meetings with personnel of the other Party or review of the other Party's records. However, the Independent Evaluator will have the right to conduct meetings, hearings or oral arguments in which both Parties are represented. The Parties may meet with each other during the review process to explore means of resolving the matter on mutually acceptable terms.

(D) The following standards shall be applied by the Independent Evaluator in rendering his or her decision:

(i) if it is not technically or operationally feasible for Seller to comply with a Performance Standard Revision, the Independent Evaluator shall determine that the Agreement shall not be amended to incorporate such Performance Standard Revision (unless the Parties agree otherwise); (ii) if it is technically or operationally feasible for Seller to comply with a Performance Standard Revision, the Independent Evaluator shall incorporate such Performance Standard Revision into a Performance Standards Revision Document including (aa) Seller's Performance Standards Modifications, (bb) pricing terms that incorporate the Performance Standards Pricing Impact, and (cc) contract terms and conditions that are commercially reasonable under the circumstances, especially with respect to the consequences of non-performance by Seller as to Performance Standards Revision(s). In addition to the Performance Standards Revision Document, the Independent Evaluator shall render a decision which sets forth the positions of the Parties and Independent Evaluator's rationale for his or her decisions on disputed issues.

(E) The fees and costs of the Independent Evaluator shall be paid by Company up to the first $30,000 of such fees and costs; above those amounts, the Party that is not the prevailing Party shall be responsible for any such fees and costs; provided, if neither Party is the prevailing Party, then the fees and costs of the Independent Evaluator above $30,000, shall be borne equally by the Parties. The Independent Evaluator in rendering his or her decision shall also state which Party prevailed over the other Party, or that neither Party prevailed over the other.

ARTICLE 24
FINANCIAL COMPLIANCE

24.1 Financial Compliance. Seller shall provide or cause to be provided to Company on a timely basis, as reasonably determined by Company, all information, including but not limited to information that may be obtained in any audit referred to below (the "Information"), reasonably requested by Company for purposes of permitting Company and HEI to comply with the requirements (initial and on-going) of (i) identifying variable interest entities and determining primary beneficiaries under the accounting principles of Financial Accounting Standards Board ("FASB") Accounting Standards Codification 810, Consolidation ("FASB ASC 810"),

(ii) Section 404 of the Sarbanes-Oxley Act of 2002 ("SOX 404") and (iii) all clarifications, interpretations and revisions of and regulations implementing FASB ASC 810 and SOX 404 issued by the FASB, Securities and Exchange Commission, the Public Company Accounting Oversight Board, Emerging Issues Task Force or other Governmental Authorities. In addition, if required by Company in order to meet its compliance obligations, Seller shall allow Company or its independent auditor to audit, to the extent reasonably required, Seller's financial records, including its system of internal controls over financial reporting; provided that Company shall be responsible for all costs associated with the foregoing, including but not limited to Seller's reasonable internal costs. Company shall limit access to such Information to persons involved with such compliance matters and restrict persons involved in Company's monitoring, dispatch or scheduling of Seller and/or Facility, or the administration of this Agreement, from having access to such Information, and persons reviewing such Information shall not participate in negotiations of amendments, modifications or clarifications of this Agreement (unless approved in writing in advance by Seller).

24.2 Confidentiality. Company shall, and shall cause HEI to, maintain the confidentiality of the Information as provided in this Article 24 (Financial Compliance). Company may share the Information on a confidential basis with HEI and the independent auditors and attorneys for HEI. (Company, HEI, and their respective independent auditors and attorneys are collectively referred to in this Article 24 (Financial Compliance) as "Recipient.") If either Company or HEI, in the exercise of their respective reasonable judgments, concludes that consolidation or financial reporting with respect to Seller and/or this PPC is necessary, Company and HEI each shall have the right to disclose such of the Information as Company or HEI, as applicable, reasonably determines is necessary to satisfy applicable disclosure and reporting or other requirements and give Seller prompt written notice thereof (in advance to the extent practicable under the circumstances). If Company or HEI disclose Information pursuant to the preceding sentence, Company and HEI shall, without limitation to the generality of the preceding sentence, have the right to disclose Information to the PUC and the Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs of the State of Hawaii ("Consumer Advocate") in connection with the PUC's

rate making activities for Company and other HEI affiliated entities, provided that, if the scope or content of the Information to be disclosed to the PUC exceeds or is more detailed than that disclosed pursuant to the preceding sentence, such Information will not be disclosed until the PUC first issues a protective order to protect the confidentiality of such Information. Neither Company nor HEI shall use the Information for any purpose other than as permitted under this Article 24 (Financial Compliance).

24.3 Required Disclosure. In circumstances other than those addressed in Section 24.2 (Confidentiality), if any Recipient becomes legally compelled under applicable Laws or by legal process (e.g., deposition, interrogatory, request for documents, subpoena, civil investigative demand or similar process) to disclose all or a portion of the Information, such Recipient shall undertake commercially reasonable efforts to provide Seller with prompt notice of such legal requirement prior to disclosure so that Seller may seek a protective order or other appropriate remedy and/or waive compliance with the terms of this Article 24 (Financial Compliance). If such protective order or other remedy is not obtained, or if Seller waives compliance with the provisions at this Article 24 (Financial Compliance), Recipient shall furnish only that portion of the Information which it is legally required to so furnish and to use commercially reasonable efforts to obtain assurance that confidential treatment will be accorded to any disclosed material.

24.4 Exclusions from Confidentiality. The obligation of nondisclosure and restricted use imposed on each Recipient under this Article 24 (Financial Compliance) shall not extend to any portion(s) of the Information which (i) was known to such Recipient prior to receipt, or (ii) without the fault of such Recipient is available or becomes available to the general public, or (iii) is received by such Recipient from a Third Party not bound by an obligation or duty of confidentiality.

24.5 Consolidation. Company is unwilling to be subject to accounting treatment that results from variable interest entity treatment as set forth in FASB ASC 810. If there is a change in circumstances during the Term that would trigger consolidation of Seller's finances on to Company's balance sheet, and such consolidation is not attributable to Company's fault, then the Parties will take all commercially reasonable steps, including modification of the Agreement,

to eliminate the consolidation, while preserving the economic "benefit of the bargain" to both Parties.

ARTICLE 25
GOOD ENGINEERING AND OPERATING PRACTICES

25.1 General. Each Party agrees to install, operate and maintain its respective equipment and facility and to perform all obligations required to be performed by such Party under this Agreement in accordance with Good Engineering and Operating Practices and applicable Laws.

25.2 Specifications, Determinations and Approvals. Wherever in this Agreement Company has the right to give specifications, determinations or approvals, such specifications, determinations or approvals shall be given in accordance with Company's standard practices, policies and procedures and shall not be unreasonably withheld.

25.3 No Endorsement, Warranty or Waiver. Any such specifications, determinations, or approvals shall not be deemed to be an endorsement, warranty, or waiver of any right of Company.

ARTICLE 26
EQUAL EMPLOYMENT OPPORTUNITY

26.1 Equal Employment Opportunity. (Applicable to all contracts of $10,000 or more in the whole or aggregate. 41 CFR 60-1.4 and 41 CFR 60-741.5.) Seller is aware of and is fully informed of Seller's responsibilities under Executive Order 11246 (reference to which include amendments and orders superseding in whole or in part) and shall be bound by and agrees to the provisions as contained in Section 202 of said Executive Order and the Equal Opportunity Clause as set forth in 41 CFR 60-1.4 and 41 CFR 60-741.5(a), which clauses are hereby incorporated by reference.

26.2 Equal Opportunity For Disabled Veterans, Recently Separated Veterans, Other Protected Veterans and Armed Forces Service Medal Veterans. Applicable to (i) contract of $25,000 or more entered into before December 31, 2003 (41 CFR 60-250.4) or (ii) each federal government contract of $100,000 or more, entered into or modified on or after December 31, 2003 (41 CFR 60-300.4) for the purchase, sale or use of personal property or nonpersonal services (including construction).) If applicable to Seller under this Agreement, Seller agrees that is, and shall remain, in compliance with the rules and regulations promulgated under The Vietnam Era Veterans

Readjustment Assistance Act of 1974, as amended by the Jobs for Veterans Act of 2002, including the requirements of 41 CFC 60-250.5(a) (for orders/contracts entered into before December 31, 2003) and 41 CFR 60-300.5(a) (for orders/contracts entered into or modified on or after December 31, 2003) which are incorporated into this Agreement by reference.

ARTICLE 27
SET OFF

Company shall have the right to set off any payment due and owing by Seller, including but not limited to any payment under this Agreement and any payment due under any arbitration award made under Article 28 (Dispute Resolution), against Company's payments of subsequent monthly invoices as necessary.

ARTICLE 28
DISPUTE RESOLUTION

28.1 Good Faith Negotiations. Except as otherwise expressly set forth in this Agreement, before submitting any claims, controversies or disputes ("Dispute(s)") under this Agreement to the Dispute Resolution Procedures set forth in Section 28.2 (Dispute Resolution Procedures), the presidents, vice presidents, or authorized delegates from both Seller and Company having full authority to settle the Dispute(s), shall personally meet in Hawaii and attempt in good faith to resolve the Dispute(s) (the "Management Meeting").

28.2 Dispute Resolutions Procedures.

(A) Mediation. Except as otherwise expressly set forth in this Agreement and subject to Section 28.1 (Good Faith Negotiations), any and all Dispute(s) arising out of or relating to this Agreement, (i) which remain unresolved for a period of 20 Days after the Management Meeting takes place or (ii) for which the Parties fail to hold a Management Meeting within 60 Days of the date that a Management Meeting was requested by a Party, may upon the agreement of the Parties, first be submitted to confidential mediation in Honolulu, Hawaii pursuant to the administration by, and in accordance with the Mediation Rules, Procedures and Protocols of, Dispute Prevention & Resolution, Inc. (or its successor) or, in their absence, the American Arbitration Association ("DPR") then in effect. If settlement of the Dispute(s)

is not reached within 60 Days after commencement of the mediation, either Party may initiate arbitration as set forth in Section 28.2(C) below.

(B) Arbitration. If (i) any Disputes remain unresolved after such mediation concludes or the 60-Day mediation period has expired, or (ii) the Parties do not mutually agree to invoke mediation procedures, the Parties agree to submit any such Dispute(s) to binding arbitration in Honolulu, Hawaii pursuant to the administration by DPR, and in accordance with (aa) the Arbitration Rules, Procedures, and Protocols of DPR then in effect (or the commercial arbitration rules then in effect of its successor) ("Arbitration Rules"), (bb) the Hawaii Revised Statutes ("HRS") Chapter 658A ("Chapter 658A") or the Federal Arbitration Act, 9 U.S.C. § 1 et seq., if applicable ("FAA"), and (cc) the procedures of this Section 28.2 (Dispute Resolution Procedures). To the extent that these procedures are permissible under Chapter 658A if the Parties agree to waive or vary the terms of the applicable Arbitration Rules and/or Chapter 658A and/or the FAA, the Parties do hereby so agree without prejudice to any application for judicial relief authorized by Chapter 658A. Capitalized and otherwise undefined terms in this Article 28 (Dispute Resolution). The final award and order of the arbitrator(s) is binding upon the Parties and judgment upon the final award and order rendered may be entered in any court of competent jurisdiction.

(C) Initiation of Arbitration. A Party shall initiate arbitration by giving to the other Party its written notice of its demand for arbitration, which notice shall include a detailed statement of its contentions of law and fact and remedies sought, and submitting such notice to DPR in accordance with the applicable Arbitration Rules. No such notice shall be valid or effective to the extent that any claim(s) set forth therein would be barred by the applicable statute of limitations or laches. Such notice shall be signed by the president of the Party giving and submitting the notice and be delivered to the president of the other Party. The other Party shall file a detailed answering statement within 20 Days of receipt of the notice of the demand for arbitration.

(D) Procedures for Appointing Arbitrator(s). The Parties hereby agree that arbitrator(s) shall be appointed

according to the following procedure, notwithstanding any contrary or inconsistent provision of the Arbitration Rules.

(1) Single Arbitrator. Within 20 Days of the receipt by the initiating Party of the detailed answering statement, the Parties shall attempt to agree on a single arbitrator with apparent and substantial experience, knowledge or expertise with respect to electric utility practices and procedures or the design, construction and operation of electric generating facilities.

(2) Three-Arbitrator Panel. Should the Parties fail to agree on a single arbitrator within such 20-Day period, each Party may appoint one arbitrator within 14 Days thereafter pursuant to the Arbitration Rules. If any Party does not appoint an arbitrator within that 14-Day period, or if the arbitrator appointed by such Party is disqualified for any reason, DPR shall appoint one or both of the arbitrator(s), as appropriate. Within 20 Days of the appointment of the second arbitrator, the two appointed arbitrators shall attempt to agree upon the appointment of a third arbitrator to serve as the chair of the panel of arbitrators. If the two appointed arbitrators fail to agree upon the appointment of the third arbitrator within this 20-Day period or if the third arbitrator appointed by the two arbitrators is disqualified for any reason, DPR shall appoint the third arbitrator. In the event of any selection of an arbitrator by DPR, the Parties hereby request that DPR give preference to the residents of the State of Hawaii. The arbitration panel shall determine all matters by majority vote.

(3) Disclosures and Objections. The Parties shall have 48 hours from the receipt of notice of the appointment of an arbitrator to request disclosures and shall have 48 hours from receipt of the notice of appointment of the arbitrator or the arbitrator's last disclosure in which to assert an objection to the arbitrator's appointment.

(E) Conduct of the Arbitration by the Arbitrator(s). Each arbitrator appointed pursuant to Section 28.2(D) shall

swear to conduct such arbitration in accordance with (i) the terms of Article 28 (Dispute Resolution), (ii) the applicable Arbitration Rules, (iii) the laws of the State of Hawaii, (iv) the most recent Guidelines for Arbitrator Reimbursement established by the Financial Industry Regulatory Authority (or its successor) and (v) the Code of Ethics of the American Arbitration Association ("Code of Ethics"), provided that, notwithstanding any thing in the Code of Ethics to the contrary, and regardless of whether appointed by a single Party, each arbitrator shall (aa) be neutral, impartial and not predisposed to favor either Party and (bb) subsequent to appointment as an arbitrator, refrain from any and all ex parte communication with any Party.

(F) Arbitration Procedures.

(1) The Parties shall have 120 Days from the date of the appointment of the single agreed arbitrator or the third arbitrator of the arbitration panel to perform discovery and present evidence and argument to the arbitrator(s), including, without limitation, all evidence and argument with respect to the costs of arbitration, attorney fees and costs, and all other matters to be considered for inclusion in the final award and order issued by the arbitrator(s).

(2) During this 120-Day period, the arbitrator(s) shall conduct a hearing to receive and consider all such evidence submitted by the Parties as the arbitrator(s) may choose to consider. The arbitrator(s) may limit the amount of time allotted to each Party presentation of evidence and argument at the hearing, provided that such time be allocated equally to each Party. Subject to the foregoing sentence, the arbitrator(s) shall have complete discretion over the mode and order of prehearing discovery, the issuance of subpoenas and subpoenas duces tecum for the production of witnesses and/or evidence prior to and at the hearing, the presentment of evidence, and the conduct of the hearing. The arbitrator(s) shall not consider any evidence or argument not presented during this 120-Day period. This 120-Day period may be extended for sufficient cause by the arbitrator(s) or by agreement of the Parties.

(3) The arbitrator(s) shall use all reasonable means to expedite discovery and may sanction a Party's non-compliance with obligations hereunder to produce evidence or witnesses prior to the hearing, at depositions or at the hearing. Each Party shall require and warrant that (i) all records of such Party, its partners, members, or affiliates pertaining to the negotiation, administration, and enforcement of this Agreement shall be maintained in the possession of such Party for no fewer than seven (7) years, and (ii) each of its officers, employees, consultants, general partners, or managing members shall submit to the jurisdiction of the arbitrator(s) and shall comply with all orders and subpoenas issued with respect to the production of witnesses or evidence at and/or prior to the hearing. All such evidence and witnesses shall made available at such Party's sole expense in Honolulu, Hawaii.

(4) Upon the conclusion of such 120-Day period, the arbitrators shall have 30 Days to reach a determination and to give a written decision to the Parties, stating their findings of fact, conclusions of law and final award and order. The final award and order shall also state which Party prevailed or that neither Party prevailed over the other.

(5) The costs of arbitration (i.e., the fees and expenses charged by the arbitrator(s) and DPR), the reasonable attorney fees of the Party that prevailed (but not including any attorney fees attributable to or charged by in-house counsel), and the reasonable costs of the Party that prevailed to the extent that such costs are recoverable pursuant to HRS § 607-9 (but not including testifying or nontestifying expert witness or consultant fees), shall be determined by the arbitrator(s) and awarded to the prevailing Party in the final award and order issued by the arbitrator(s); provided, however, that the arbitrator(s) shall have no power to award any costs of arbitration, attorney fees or costs incurred more than thirty (30) Days prior the date of the notice and demand for arbitration. In the event neither Party prevails, the Parties shall

each pay fifty percent (50%) of the cost of the arbitration (i.e., the fees and expenses charged by the arbitrator(s) and DPR) and shall otherwise each bear their own arbitration costs, attorney fees, costs and all other expenses of arbitration, including without limitation their own testifying or nontestifying expert witness and consultant fees.

(6) To the extent the final award and order directs either Party to pay any amounts to the other Party, including monetary damages, costs of arbitration, or reasonable attorney fees and costs:

(a) if neither Party seeks judicial review of the final award and order, payment shall be made within ninety-five (95) days after the final award and order is issued;

(b) if either Party seeks judicial review of the final award and order, payment shall be made within thirty (30) days after the available judicial review is exhausted.

(G) Authority of the Arbitrators. Notwithstanding anything herein or in the Arbitration Rules to the contrary, the authority of the arbitrator(s) in rendering the final award and order is limited to the interpretation and/or application of the terms of this Agreement and to ordering any remedy allowed by this Agreement. The arbitrator(s) shall have no power to change any term or condition of this Agreement, deprive any Party of a remedy expressly provided hereunder, or provide any right or remedy that has been excluded hereunder. Notwithstanding anything herein or in the Arbitration Rules to the contrary, any Party who contends that the final award and order of the arbitrator(s) was in excess of the authority of the arbitrator(s) as set forth herein may seek judicial relief in the Circuit Court of the State of Hawaii for the circuit in which the arbitration hearing was held, provided that such judicial proceeding is initiated within 30 Days of the final award and order and not otherwise.

28.3 The provisions of this Article 28 (Dispute Resolution) shall not apply to any disputes within the authority of an Independent Evaluator under Article 23 (Process for Addressing Revisions to Performance Standards).

ARTICLE 29
REGULATORY COMPLIANCE

29.1 Seller shall file in Docket No. 2008-0273, subject to protective order, the following information within thirty (30) days of the In-Service Date and annually thereafter.

(A) The cost of design, permitting, and construction costs, including labor and materials costs of the Facility;
(B) Financing or capital cost;
(C) Land cost or actual cost of Site acquisition
(D) Interconnection and metering costs incurred by the Seller;
(E) Other project costs incurred in developing and constructing the Facility;
(F) Tax credits, rebates, incentives received and applied to the project development cost;
(G) Maintenance and operation labor and non-labor costs;
(H) Fuel supply costs (for biomass and biogas projects);
(I) Monthly land or leases costs for the Site; and
(J) Other operations and maintenance costs.

29.2 Additionally, Seller shall file an annual report with the Commission in Docket No. 2008-0273, no later than January 31, of each year, which contains the following information: (i) annual electric energy production in kWh; and (ii) annual operating costs, including operations and maintenance costs, lease expenses, insurance, and property taxes.

ARTICLE 30
MISCELLANEOUS

30.1 Amendments. Any amendment or modification of this Agreement or any part hereof shall not be valid unless in writing and signed by the Parties. Any waiver hereunder shall not be valid unless in writing and signed by the Party against whom waiver is asserted. Notwithstanding the foregoing, administrative changes mutually agreed by Company and Seller in writing, such as changes to settings shown in the Three-Line Drawing (Attachment E) and the Relay List and Trip Scheme (Attachment F) and changes to numerical values of

performance standards in Section 3 (Performance Standards) of Attachment B (Facility owned by Company) shall not be considered amendments to this Agreement requiring PUC approval.

30.2 Binding Effect. This Agreement shall be binding upon and inure to the benefit of the Parties hereto and their respective successors, legal representatives, and permitted assigns.

30.3 Notices.

(A) All notices, consents and waivers under this Agreement shall be in writing and will be deemed to have been duly given when (i) delivered by hand, (ii) sent by telecopier (with printed confirmation of transmission), (iii) sent by certified mail, return receipt requested, or (iv) when received by the addressee, if sent by a nationally recognized overnight delivery service (receipt requested), in each case to the appropriate addresses and telecopier numbers set forth below (or to such other addresses and facsimile numbers as a Party may designate by notice to the other Party):

Company:

By Mail:
Hawaiian Electric Company, Inc.
PO BOX 2750
Honolulu, Hawaii 96840-0001
Attn: Director, Energy Contractor Administration Division

Delivered:
Hawaiian Electric Company, Inc.
Waiau Power Plant, Adm 1st fl.
475 Kamehameha Highway
Pearl City, HI 96782

Attn: Director, Energy Contractor Administration Division

By facsimile:
Director, Energy Contractor Administration Division
(808) 203-1801

(B) Seller: The mailing address and facsimile number listed in Attachment A (Description of Generation and Conversion Facility) hereto.

(C) Notice sent by mail shall be deemed to have been given on the date of actual delivery or at the expiration of the fifth Day after the date of mailing, whichever is earlier. Any Party hereto may change its address for written notice by giving written notice of such change to the other Party hereto.

(D) Any notice delivered by facsimile shall be followed by personal or mail delivery and the effective date of such notice shall be the date of personal delivery or, if by mail, the earlier of the actual date of delivery or the expiration of the fifth Day after the date of mailing.

(E) The Parties may agree in writing upon additional means of providing notices, consents and waivers under this Agreement in order to adapt to changing technology and commercial practices.

30.4 Effect of Section and Attachment Headings. The headings or titles of the several sections and attachments hereof are for convenience of reference and shall not affect the construction or interpretation of any provision of this Agreement.

30.5 Non-Waiver. Except as otherwise provided in this Agreement, no delay or forbearance of Company or Seller in the exercise of any remedy or right will constitute a waiver thereof, and the exercise or partial exercise of a remedy or right shall not preclude further exercise of the same or any other remedy or right.

30.6 Relationship of the Parties. Nothing in this Agreement shall be deemed to constitute either Party hereto as partner, agent or representative of the other Party or to create any fiduciary relationship between the Parties. Seller does not hereby dedicate any part of Facility to serve Company, Company's customers or the public.

30.7 Entire Agreement. This Agreement (together with any confidentiality or non-disclosure agreements entered into by the Parties during the process of negotiating this Agreement and/or discussing the specifications of the Facility) constitutes the entire agreement between the Parties relating to the subject matter hereof, superseding all prior

agreements, understandings or undertakings, oral or written. Each of the Parties confirms that in entering into this Agreement, it has not relied on any statement, warranty or other representations (other than those set out in this Agreement) made or information supplied by or on behalf of the other Party.

30.8 Governing Law, Jurisdiction and Venue. Interpretation and performance of this Agreement shall be in accordance with, and shall be controlled by, the laws of the State of Hawaii, other than the laws thereof that would require reference to the laws of any other jurisdiction. By entering into this Agreement, Seller submits itself to the personal jurisdiction of the courts of the State of Hawaii and agrees that the proper venue for any civil action arising out of or relating to this Agreement shall be Honolulu, Hawaii.

30.9 Limitations. Nothing in this Agreement shall limit Company's ability to exercise its rights as specified in Company's Tariff as filed with the PUC, or as specified in General Order No. 7 of the PUC's Standards for Electric Utility Service in the State of Hawaii, as either may be amended from time to time.

30.10 Further Assurances. Each of the Parties shall from time to time and at all times do such further acts and deliver all such further documents and assurances as shall be reasonably necessary fully to perform and carry out this Agreement.

30.11 Facsimile Signatures and Counterparts. This Agreement may be executed and signatures transmitted electronically via the Internet or facsimile. This Agreement may be executed in counterparts, each of which shall be deemed an original, and all of which shall together constitute one and the same instrument binding all Parties notwithstanding that all of the Parties are not signatories to the same counterparts. For all purposes, duplicate unexecuted and unacknowledged pages of the counterparts may be discarded and the remaining pages assembled as one document.

30.12 Definitions. Capitalized terms used in this Agreement not otherwise defined in the context in which they first appear are defined in the Definitions Section.

30.13 Severability. If any term or provision of this Agreement, or the application thereof to any person, entity or circumstances is to any extent invalid or unenforceable, the remainder of this Agreement, or the application of such term

or provision to persons, entities or circumstances other than those as to which it is invalid or unenforceable, shall not be affected thereby, and each term and provision of this Agreement shall be valid and enforceable to the fullest extent permitted by law, and the Parties will take all commercially reasonable steps, including modification of the Agreement, to preserve the economic "benefit of the bargain" to both Parties notwithstanding any such aforesaid invalidity or unenforceability.

30.14 Settlement of Disputes. Except as otherwise expressly provided, any dispute or difference arising out of this Agreement or concerning the performance or the non-performance by either Party of its obligations under this Agreement shall be determined in accordance with the dispute resolution procedures set forth in Article 28 (Dispute Resolution) of this Agreement.

30.15 Environmental Credits. To the extent not prohibited by law, any Environmental Credit shall be the property of Company; provided, however, that such Environmental Credits shall be to the benefit of Company's ratepayers in that the value must be credited "above the line". Seller shall use all commercially reasonable efforts to ensure such Environmental Credits are vested in Company, and shall execute all documents, including, but not limited to, documents transferring such Environmental Credits, without further compensation; provided, however, that Company agrees to pay for all reasonable costs associated with such efforts and/or documentation.

30.16 Attachments. Each Attachment constitutes an essential and necessary part of this Agreement.

30.17 Proprietary Rights. Seller agrees that in fulfilling its responsibilities under this Agreement, it will not use any process, program, design, device or material that infringes on any United States patent, trademark, copyright or trade secret ("Proprietary Rights"). Seller agrees to indemnify, defend and hold harmless Company from and against all losses, damages, claims, fees and costs, including but not limited to reasonable attorneys' fees and costs, arising from or incidental to any suit or proceeding brought against Company for infringement of Third Party Proprietary Rights arising out of Seller's performance under this Agreement, including but not limited to patent infringement due to the use of technical features of the Facility to meet the Performance Standards specified in the Agreement.

30.18 Negotiated Terms. The Parties agree that the terms and conditions of this Agreement are the result of negotiations between the Parties and that this Agreement shall not be construed in favor of or against any Party by reason of the extent to which any Party or its professional advisors participated in the preparation of this Agreement.

30.19 Computation of Time. In computing any period of time prescribed or allowed under this Agreement, the Day of the act, event or default from which the designated period of time begins to run shall not be included. If the last Day of the period so computed is not a Business Day, then the period shall run until the end of the next Day which is a Business Day.

30.20 Change in Standard System or Organization.

(A) Consistent With Original Intent.

If, during the Term, any standard, system or organization referenced in this Agreement should be modified or replaced in the normal course of events, such modification or replacement shall from that point in time be used in this Agreement in place of the original standard, system or organization, but only to the extent such modification or replacement is generally consistent with the original spirit and intent of this Agreement.

(B) Eliminated or Inconsistent With Original Intent.

If, during the Term, any standard system or organization referenced in this Agreement should be eliminated or cease to exist, or is modified or replaced and such modification or replacement is inconsistent with the original spirit and intent of this Agreement, then in such event the Parties will negotiate in good faith to amend this Agreement to a standard, system or organization that would be consistent with the original spirit and intent of this Agreement.

30.21 Headings. The Table of Contents and headings of the various sections have been inserted in this Agreement as a matter of convenience for reference only and shall not modify, define or limit any of the terms or provisions hereof and shall not be used in the interpretation of any term or provision of this Agreement.

30.22 No Third Party Beneficiaries. Nothing expressed or referred to in this Agreement will be construed to give any person or entity other than the Parties any legal or equitable right, remedy, or claim under or with respect to this Agreement or any provision of this Agreement. This Agreement and all of its provisions and conditions are for the sole and exclusive benefit of the Parties and their successors and permitted assigns.

30.23 Hawaii General Excise Tax. Seller shall, when making payments to Company under this Agreement, pay such additional amount as may be necessary to reimburse Company for any tax liability imposed on Company as a result of the receipt of such payment (including receipt of any payment made under this Section 30.24 (Hawaii General Excise Tax)). By way of example and not limitation, as of the Execution Date, all payments subject to the 4.5% Hawaii general excise tax on Oahu would include an additional 4.71% so that the underlying payment will be net of such tax liability.

30.24 Survival of Obligations. The rights and obligations that are intended to survive a termination of this Agreement are all of those rights and obligations that this Agreement expressly provides shall survive any such termination and those that arise from Seller's or Company's covenants, agreements, representations, and warranties applicable to, or to be performed, at or during any time prior to or as a result of the termination of this Agreement, including, without limitation:

(A) The obligation to pay Daily Delay Damages under Section 13.4 (Damages and Termination);

(B) The obligation to pay Termination Damages under Article 16 (Damages in the Event of Termination by Company);

(C) The indemnity obligations under Article 17 (Indemnification);

(D) The dispute resolution provisions of Article 28 (Dispute Resolution); and

(E) Section 30.3 (Notices), Section 30.5 (Non-Waiver), Section 30.8 (Governing Law, Jurisdiction and Venue), Section 30.9 (Limitations), Section 30.13 (Severability), Section 30.14 (Settlement of Disputes), Section 30.15 (Environmental Credits), Section 30.17 (Proprietary Rights), Section 30.19 (Computation of

Time), Section 30.22 (No Third Party Beneficiaries), Section 30.23 (Hawaii General Excise Tax), and Section 30.24 (Survival of Obligations).

30.25 Certain Rules of Construction.

For purposes of this Agreement:

(A) "Including" and any other words or phrases of inclusion will not be construed as terms of limitation, so that references to "included" matters will be regarded as non-exclusive, non-characterizing illustrations.

(B) "Copy" or "copies" means that the copy or copies of the material to which it relates are true, correct and complete.

(C) When "Article," "Section," "Schedule," or "Attachment" is capitalized in this Agreement, it refers to an article, section, schedule or attachment to this Agreement.

(D) "Will" has the same meaning as "shall" and, thus, connotes an obligation and an imperative and not a futurity.

(E) Titles and captions of or in this Agreement, the cover sheet and table of contents of this Agreement, and language in parenthesis following Section references are inserted only as a matter of convenience and in no way define, limit, extend or describe the scope of this Agreement or the intent of any of its provisions.

(F) Whenever the context requires, the singular includes the plural and plural includes the singular, and the gender of any pronoun includes the other genders.

(G) Any reference to any statutory provision includes each successor provision and all applicable Laws as to that provision.

[Signatures for Tier 3 Feed-In Tariff Power Purchase Agreement appear on the following page]

IN WITNESS WHEREOF, Company and Seller have executed this Agreement as of the day and year first above written.

_____

By_____
Name:
Its:

By_____
Name:
Its:

("Company")

_____

By_____
Name:
Its:

By_____
Name:
Its:

("Seller")

ATTACHMENT A
DESCRIPTION OF GENERATION AND CONVERSION FACILITY

1. Name of Facility: _____

   (A) Location: _____

   (B) Telephone number (for system emergencies):

   ( ) -

   (C) Facsimile number: ( ) -

2. Owner (If different from Seller):

   _____

   By Execution Date, Seller shall provide Company with a certified copy of a certificate warranting that the owner is a corporation, partnership or limited liability company in good standing with the Hawaii Department of Commerce and Consumer Affairs.

3. Operator: _____

4. Name of person to whom payments are to be made:

   _____

   (A) Mailing address: _____

   _____

   (B) Hawaii Gross Excise Tax License number: _____

5. Equipment:

   (A) Type of facility and conversion equipment:

   [For example: Small power production facility designated as a Qualifying Facility that produces electric energy using _____.]

   (B) Design and capacity

   Total Facility Capacity ("Contract Capacity"):
   _____kW

   Total Number of Generators:

[number and size of each generator. e.g. one (1) Brand X, 200 kW; one (1) Brand Y, 300 kW]

Description of Equipment:

[For example: Describe the type of energy conversion equipment, capacity, and any special features.]

Individual unit: [if more than one generator, list information for each generator]

	kW	kVAR Consumed	kVAR Produced
Full load			
Startup			

Generator:

Type	_____
Rated Power	__ kW
Voltage	__ V, _ phase
Frequency	__ HZ
Class of Protection	_____
Number of Poles,	
if applicable	_____
Rated Speed,	
if applicable	__ rpm
Rated Current	___ A
Uncorrected Power Factor	_____
Corrected Power Factor	_____
Corrected Current	___ A

(C) Single or 3 phase: _ phase

(D) Name of manufacturer:

(E) The "Allowed Capacity" of this Agreement shall be the lower of (i) Contract Capacity or (ii) the net nameplate capacity (net for export) of the Facility installed on the In-Service Date.

6. Insurance carrier(s):

7. If Seller is not the operator, Seller shall provide a copy of the agreement between Seller and the operator which requires the operator to operate the Facility and which establishes the scope of operations by the operator and the respective rights of Seller and the operator with respect to the sale of electric energy from Facility no later than the In-Service Date. Seller shall provide a certified copy of a certificate warranting that the operator is a corporation, partnership or limited liability company in good standing with the Hawaii Department of Commerce and Consumer Affairs.

8. If Seller is the operator, Seller shall provide a certified copy of a certificate warranting that Seller is a corporation, partnership or limited liability company in good standing with the Hawaii Department of Commerce and Consumer Affairs.

9. Seller, owner and operator shall provide Company a description of their ownership structures.

10. Any certificate or description of ownership structure required under this Attachment A (Description of Generation and Conversion Facility) shall be provided to Company by the Execution Date. In the event of a change in ownership or identity of Seller, owner or operator, such entity shall provide within 30 Days thereof, a certified copy of a new certificate and a revised ownership structure.

ATTACHMENT B
FACILITY OWNED BY SELLER

1. The Facility

(A) Three-Line Diagram, Relay List, Relay Settings and Trip Scheme. A preliminary Three-Line diagram, relay list, relay settings, and trip scheme of the Facility shall, after Seller has obtained prior written consent from Company, be attached to this Agreement on the Execution Date as Attachment E (Three-Line Drawing) and Attachment F (Relay List and Trip Scheme). A final Three-Line drawing, relay list and trip scheme of the Facility shall, after having obtained prior written consent from Company, be attached as labeled "Final" Attachment E (Three-Line Drawing) and Attachment F (Relay List and Trip Scheme) to this Agreement and made a part hereof on the In-Service Date. After the In-Service Date, no changes shall be made to the "Final" Attachment E (Three-Line Drawing) and Attachment F (Relay List and Trip Scheme) without the prior written consent of Seller and Company. The Three-Line diagrams shall expressly identify the Point of Interconnection of Facility to Company System. Seller agrees that no material changes or additions to Facility as reflected in the final Three-Line diagram, relay list and trip scheme shall be made without Seller first having obtained prior written consent from Company. If any changes in or additions to the Facility, records and operating procedures are required by Company, Company shall specify such changes or additions to Seller in writing, and, except in the case of an emergency, Seller shall have the opportunity to review and comment upon any such changes or additions in advance.

(B) Certain Specifications for the Facility.

(i) Seller shall furnish, install, operate and maintain the Facility including breakers, relays, switches, synchronizing equipment (if applicable), monitoring equipment and control and protective devices approved by Company as suitable for parallel operation of the Facility with Company System. The Facility shall be accessible at all times to authorized Company personnel.

(ii) The Facility shall include:

[LIST OF THE FACILITY

Examples may include, but not limited to:

- **Seller-Owned Interconnection Facilities**
- **Substation**
- **Control and monitoring facilities**
- **Transformers**
- **Generators (as described in Attachment A)**
- **"lockable" cabinets or housings suitable for the installation of the Company-Owned Interconnection Facilities located on the Site**
- **relays and other protective devices**
- **leased telephone line and/or equipment to facilitate microwave communication]**

(iii) The Facility will comply with the following **[includes excerpts of language that may be requested by Company]**:

(a) Company will install as part of Company-Owned Interconnection the Facilities to be constructed by Company and reimbursed by Seller, a manually operated, lockable, disconnect switch located on the pole adjacent to the Facility switching station. Company will install a ____ kV drop into Seller-provided metering structure. Seller will install a ____ kV disconnect switch and all other items for its switching station (relaying, control power transformers, high voltage circuit breaker). Bus connection will be made to a manually and automatically (via protective relays) operated high-voltage circuit breaker. The high-voltage circuit breaker will be fitted with bushing style current transformers for metering and relaying. Downstream of the high-voltage circuit breaker, a structure will be provided for metering transformers. From the high-voltage circuit breaker, another bus connection will be made to another pole mounted disconnect switch, with surge protection.

(b) Seller will provide within the Seller-Owned Interconnection Facilities a separate, fenced area with separate access for Company. Seller will provide revenue metering PTs and CTs (as specified by Company) and all conduits and accessories necessary for Company to install Company-supplied revenue meters. Seller will also provide within such area, space for Company to install its communications, supervisory control and data acquisition ("SCADA") remote terminal unit ("RTU") and certain relaying if necessary for the interconnection. Seller will also provide AC and DC source lines as specified later by Company. Seller will provide a telephone line for Company-Owned meters. Seller will work with Company to determine an acceptable location and size of the fenced-in area. Seller shall provide an acceptable demarcation cabinet on its side of the fence where Seller and Company wiring will connect/interface.

(c) Seller shall ensure that the Seller-Owned Interconnection Facilities has a lockable cabinet for switching station relaying equipment. Seller shall select and install relaying equipment acceptable to Company. At a minimum the relaying equipment will provide over and under frequency (81) negative phase sequence (46), under voltage (27), over voltage (59), ground over voltage (59G), over current functions (50/51) and direct transfer trip. Seller shall install protective relays that operate a lockout relay, which in turn will trip the main circuit breaker.

(d) The relay protection system will be configured to provide overpower protection to enable Facility to comply with the Allowed Capacity limitation.

(e) Seller's equipment also shall provide at a minimum:

i. Interface with Company's RTU to provide telemetry of electrical quantities such as total Facility net MW, MVar, and power factor, voltages, currents, and other quantities as identified by the Company;

ii. Interface with Company's RTU to provide status for circuit breakers, reactive devices, switches, and other equipment as identified by the Company;

iii. Interface with Company's RTU to provide control to incrementally raise and lower the voltage target at the Point of Interconnection (if voltage regulation is required) or change the power factor control (if power factor control is required);

iv. Interface with Company's RTU to provide curtailment control to incrementally limit (curtail) Actual Output from the Facility and to incrementally remove the limit (curtail) of the Actual Output of the Facility. The incremental size will be determined as part of the Interconnection Requirements Study taking into account the size of the Facility;

v. For Wind Facilities: Interface with Company's RTU to provide telemetry of environmental data such as measured wind speed and direction and the Facility's calculated available power based on Wind Turbine availability and turbine status; and

vi. For PV Facilities: Interface with Company's RTU to provide telemetry of insolation measurements and calculated available power based on PV panel and/or inverter availability and status of PV panel and/or inverter availability.

(f) If Seller adds, deletes and/or changes any of its equipment, or changes its design in a manner that would change the characteristics of the equipment and specifications used in

the IRS, Seller will be required to obtain Company's prior written approval. If an analysis to revise parts of the IRS is required, Seller will be responsible for the cost of revising those parts of the IRS, and modifying and paying for the cost of the modifications to the Facility and/or the Company-Owned Interconnection Facilities based on the revisions to the IRS.

(C) Design Drawings, Bill of Materials, Relay Settings and Fuse Selection. Seller shall provide to Company for its review the design drawings, Bill of Material, relay settings and fuse selection for the Facility and Company shall have the right, but not the obligation, to specify the type of electrical equipment, the interconnection wiring, the type of protective relaying equipment, including, but not limited to, the control circuits connected to it and the disconnecting devices, and the settings that affect the reliability and safety of operation of Company's and Seller's interconnected system. Seller shall provide the relay settings, fuse selection, and AC/DC Schematic Trip Scheme (part of design drawings) for the Facility to Company at least sixty (60) Days prior to the Acceptance Test. Company, at its option, may, with reasonable frequency, witness Seller's operation of control, synchronizing, and protection schemes and shall have the right to periodically re-specify the settings. Seller shall utilize relay settings prescribed by Company, which may be changed over time as Company System requirements change.

(D) Disconnect Device. Seller shall provide a manually operated disconnect device which provides a visible break to separate Facility from Company System. Such disconnect device shall be lockable in the OPEN position and be readily accessible to Company personnel at all times.

(E) Other Equipment. Seller shall furnish, install and maintain in accordance with Company's requirements all conductors, service switches, fuses, meter sockets, meter (includes revenue metering structure, CT(s) and PT(s) and accessories) and instrument transformer housing and mountings, switchboard meter test buses,

meter panels and similar devices required for service connections and meter installations at the Site.

(F) Maintenance Plan. Seller shall maintain Seller-Owned Interconnection Facilities in accordance with the following maintenance plan:

Transmission line: [redacted]

[redacted] kV Facility switching station: [redacted]

Relay protection equipment: [redacted]

Revenue Metering PTs and CTs: every 5 years

Other equipment as identified: [redacted]

Seller shall furnish to Company a copy of records documenting such maintenance, within thirty (30) Days of completion of such maintenance work.

(G) Curtailment Control Interface.

(i) Seller shall provide and maintain in good working order all equipment, computers and software associated with the control system (the "Curtailment Control Interface") necessary for real power control of the facility. The Curtailment Control Interface will be used to control the maximum level of the Actual Output from the Facility when required under this Attachment B (Facility Owned by Seller). The implementation of the Curtailment Control Interface will allow Company System Operator to initiate the curtailment, vary the level of curtailment, and remove the curtailment remotely from Company System Operations Control Center through control signals from Company's computerized control system (SCADA/EMS). If the Curtailment Control Interface fails, the Facility shall automatically fully curtail itself.

(ii) Company shall review and provide prior written approval of the design for the Curtailment Control Interface to ensure compatibility with Company's SCADA/EMS system. If Seller materially changes the approved design, such changes will

also require Company's review and prior written approval.

(iii) The Curtailment Control Interface shall include, but not be limited to, a demarcation cabinet, ancillary equipment and software necessary for Seller to connect to Company's RTU, located in Company's portion of the Facility switching station which shall provide the control signals to the Facility and send feedback status to the Company System Operations Control Center. The types of controls presently supported by Company's SCADA/EMS system include fixed-length digital output controls, variable length digital output (pulse-width output) controls, and analog output (set point) controls. **[NOTE: THE SPECIFIC TYPE OF CONTROL USED FOR THE FACILITY WILL BE DETERMINED BY THE COMPANY AS PART OF THE IRS.]**

(iv) The Curtailment Control Interface shall also include provision for a feedback point from the Facility indicating when curtailment is in effect and the analog value of the curtailment MW limit.

(v) The Curtailment Control Interface shall provide for remote control of the real-power output of the Facility by the Company at all times. If the Curtailment Control Interface is unavailable or disabled, the Facility shall not export electric energy to Company, unless the Company, in its sole discretion, agrees to accept electric energy and Seller and Company agree on an alternate means of curtailment. Notwithstanding the foregoing, if Seller fails to provide such remote control features (whether temporary or throughout the Term) and fails to discontinue exporting electric energy to Company as required by this Section 1(G)(v), then, notwithstanding any other provision of this Attachment B (Facility Owned by Seller), Company shall have the right to curtail the entire Facility during those periods that such control features are not provided.

(vi) The rate at which the Facility reduces Actual Output shall not exceed the ramp rate specified in Section 3(C) of Attachment B (Facility Owned by Seller). The Facility's Curtailment Control

Interface will control the rate at which electric energy is reduced to achieve the curtailment limit. The Facility will respond to the curtailment request immediately and within minimum rate response of 0.5 MW/min.

(vii) The requirements of the Curtailment Control Interface may be modified as mutually agreed upon in writing by the Parties.

(H) Control System Acceptance Test Procedures. Following the successful completion of the Acceptance Test, the Control System Acceptance Test(s) shall be conducted on the centralized control system of the Facility as each generator is designated by Seller to be ready to generate and deliver electric energy to Company, before that generator is included in Facility. No later than thirty (30) Days prior to conducting the Control System Acceptance Test, Company and Seller shall agree on a written protocol setting out the detailed procedure and criteria for passing the Control System Acceptance Test. Attachment O (Control System Acceptance Test Criteria) provides general criteria to be included in the written protocol for the Control System Acceptance Test. Within fifteen (15) Business Days of successful completion of the Control System Acceptance Test, Company shall notify Seller in writing that the Control System Acceptance Test(s) has been passed and the date upon which such Control System Acceptance Test(s) was passed.

2. Operating Procedures **[NOTE: NUMERICAL SPECIFICATIONS IN THIS SECTION 2 MAY VARY DEPENDING ON THE SPECIFIC PROJECT AND THE RESULTS OF THE PROJECT SPECIFIC INTERCONNECTION REQUIREMENT STUDY.]**

(A) Reviews of the Facility. Company may require periodic reviews of the Facility, maintenance records, available operating procedures and policies, and relay settings, and Seller shall implement changes Company deems necessary for parallel operation or to protect the Company System from damages resulting from the parallel operation of the Facility with the Company System.

(B) Separation. Seller must separate from Company System whenever requested to do so by the Company System Operator pursuant to Article 8 (Continuity of Service) and Article 9 (Personnel and System Safety) of the Agreement.

(C) Seller Logs. Logs shall be kept by Seller for information on unit availability including reasons for planned and forced outages; circuit breaker trip operations, relay operations, including target initiation and other unusual events. Company shall have the right to review these logs, especially in analyzing system disturbances. Seller shall maintain such records for a period of not less than thirty-six (36) months.

(D) Reclosing. Under no circumstances shall Seller, when separated from the Company System for any reason, reclose into the Company System without first obtaining specific approval to do so from the Company System Operator.

(E) Direct Transfer Trip.

If the direct transfer trip is unavailable, due to loss of communication link, RTU failure, or other event resulting in the loss of the remote control by the Company, provisions must be made for the Seller to trip the main circuit breaker.

(F) Curtailment Methodology.

(i) Pursuant to Article 8 (Continuity of Service), and Article 9 (Personnel and System Safety), of the Agreement, Company may at times have limited ability to integrate energy produced by Seller into the Company System for engineering and/or operating reasons and may be required to curtail energy deliveries by Seller. When a curtailment control signal is received by the Facility through the Curtailment Control Interface, the corresponding action (e.g., decrease in the Facility's output) shall be initiated without delay. Further curtailment may be implemented if conditions warrant and the Company System Operator deems it necessary. As conditions warrant, Company shall end or reduce the curtailment when Company reasonably determines that the reason for the curtailment is no longer in existence. The Company System Operator shall end or reduce the curtailment through the Curtailment Control Interface. Seller may request that the Facility be restored no sooner than one hour after Company has curtailed the Facility.

(ii) When the Company determines that curtailment of energy becomes necessary for reasons other than those directly attributable to the Seller's Facility, curtailments shall be made to the extent possible in reverse chronological order of the chronological seniority dates determined by Company for its power purchase agreements for as-available energy, including Schedule FIT Agreements, with deliveries under such agreements with the most recent chronological seniority date being the first curtailed, and deliveries under such agreements with the earliest chronological seniority date being the last curtailed. When the Company determines that curtailment of energy becomes necessary for engineering and/or operating reasons that are directly attributable to the Seller's Facility, reverse chronological curtailment order may not apply.

(iii) The Company shall not be liable to the Seller for any such curtailments unless they were in violation of Article 8 (Continuity of Service) or Article 9 (Personnel and System Safety) of this Agreement. Seller shall not override Company's curtailment.

(iv) For the purpose of this Agreement, if the Facility has a Design Capacity above the trigger for Supervisory Control and Data Acquisition ("SCADA") set forth in the Company Tariff, Rule 14, Section H, or the Company, in its sole discretion, has deemed that an alternate means of curtailment is technically feasible for such Facility ("Curtailable Facilities"), such Facility shall be grouped together in one or more blocks (each a "FIT Block") determined in accordance with this Section 2(F) (Curtailment Methodology) of Attachment B (Facility Owned by Seller). A FIT Block will consist of all Curtailable Facilities that applied for Schedule FIT in the same Schedule FIT release phase ("Schedule FIT Phase"). Each FIT Block will be assigned a date corresponding to the date on which the particular Schedule FIT Phase was made available to the public for applications ("FIT Block Release Date"). The chronological

seniority date with respect to Schedule FIT Agreements shall be the FIT Block Release Date.

(v) If the Curtailment Control Interface is unavailable, due to loss of communication link, RTU failure, or other event resulting in the loss of the remote control by Company, provision must be made for Seller to be able to institute, within 30 minutes or such other period as Company accepts in writing, local curtailment raise and lower control and change in voltage regulation target via the local controls upon verbal request by the Company System Operator.

3. Performance Standards

(A) Reactive Power Control.

Company may designate voltage control, constant Mvar, or power factor control. If constant voltage control is specified Seller shall regulate the voltage at the Point of Interconnection to a voltage specified by Company System Operator. If power factor control is required, the power factor at which energy is to be delivered by Seller to Company shall be adjustable and adjusted as necessary, to the specified power factor. The reactive power range will be determined by the Interconnection Requirements Study. The design for the voltage regulation/power factor control will be reviewed and approved by Company.

(B) Reactive Amount **[THESE REQUIREMENTS MAY BE CHANGED BY THE COMPANY UPON COMPLETION OF THE IRS.]**

(i) The Facility will provide reactive power for the range of 0.85 export to 0.90 import, or the requirement specified by the Interconnection Requirements Study, which ever range is greater.

(ii) Company will not be obligated to purchase reactive power from Seller. The Facility shall contain equipment able to continuously and actively control the output of reactive power, based on the control mode designated by the Company and to react to system fluctuations. The reactive response speed at the Point of Interconnection shall be able to achieve [ ] of its final value within [ ] following a step

change in voltage. **[REACTIVE POWER REQUIREMENTS WILL BE DETERMINED BY THE COMPANY UPON COMPLETION OF THE IRS.]**

(iii) If the Facility does not operate in accordance with Section 3(B)(i) of this Attachment B (Facility Owned by Seller), Company may disconnect all or a part of Facility from Company System until Seller corrects its operation (such as by installing capacitors at Seller's expense).

(C) Ramp Rates **[TO BE DETERMINED BY THE COMPANY UPON COMPLETION OF THE IRS]**

Seller shall ensure that the ramp rate of the Facility are less than the following limits for all conditions including start up, normal operations, and shut down (including high wind speed shut down in the case of Wind Facilities) for the following periods. Note that time periods are subject to seasonal variations and typical times of day/night are provided for general planning purposes only.

- Maximum Ramp Rate Upward of **[TBD]** MW/minute for all periods except during Early Morning Low-Load Periods (typically Midnight to 4:00 am) where Maximum Ramp Rate Upward is **[TBD]** MW/minute.

- Maximum Ramp Rate Downward of **[TBD]** MW/minute for all periods except during Evening Periods (typically 4:00 pm to 8:00 pm)where Maximum Ramp Rate Downward is **[TBD]** MW/minute.

(D) Power Fluctuation Rate

Seller shall ensure that the power fluctuation rate of the Facility is less than the following limit for all conditions including start up, normal operations, and shut down:

Instantaneous: 1 megawatt/2-second scan

Subminute Average: an average of 0.3 megawatt/2-second scan for any 60-second period

(E) Undervoltage Ride-Through

The Facility (as a whole) will meet the following undervoltage ride-through requirements during low voltage affecting one or more of the three voltage phases ("V" is the voltage of any three voltage phases at the point of interconnection). **[THESE VALUES MAY BE CHANGED BY THE COMPANY UPON COMPLETION OF THE IRS.]**:

$V \geq 0.80$ pu	The Facility remains connected to the Company System.
0.75 pu $\leq V \leq 0.80$ pu	The Facility may initiate disconnection from the Company System if the voltage remains in this range for more than 2 seconds.
0.00 pu $\leq V \leq 0.75$ pu	The Facility may initiate disconnection from the Company System if voltage remains in this range for more than 600 milliseconds.

(F) Over voltage ride-through

The overvoltage protection equipment at the Facility shall be set so that the Facility will meet the following overvoltage ride-through requirements during voltage affecting one or more of the three voltage phases (as described below) ("V" is the voltage of any of the three voltage phases at the point of interconnection). **[THESE VALUES MAY BE CHANGED BY THE COMPANY UPON COMPLETION OF THE IRS.]**

1.00 pu $\leq V < 1.10$ pu	The Facility remains connected to the Company System.
1.10 pu $\leq V < 1.15$ pu	The Facility may initiate disconnection from the Company System if voltage remains in this range for more than 3 seconds.

1.15 pu ≤ V < 1.175 pu	The Facility may initiate disconnection from the Company System if voltage remains in this range for more than 2 seconds.
1.175 pu ≤ V < 1.2 pu	The Facility may initiate disconnection from the Company System if voltage remains in this range for more than 1 second.
1.2 pu < V	The Facility may initiate disconnection from the Company System immediately.

(G) Transient ride-through

The Facility shall be designed such that the transient stability of Company System is maintained for (1) three-phase fault located anywhere on the Company System and lasting up to ___ cycles; and (2) a single line to ground fault located anywhere on the Company System and lasting up to ___ cycles. **[RIDE-THROUGH REQUIREMENTS WILL BE DETERMINED BY THE COMPANY UPON COMPLETION OF THE IRS.]**

(H) Fault Ride Through

For fault-related voltage dips at the Point of Interconnection that stay within the limits of the under voltage ride-through requirements in Section 3(E) above, upon clearing of the fault, Seller shall within 1 second of restoration, provide at least 90% of the real power output at the point of interconnection immediately before the fault. This does not apply if the Facility was operating at less than 5% of its rated MW capacity.

(I) Underfrequency ride-through

The Facility shall meet the following underfrequency ride-through requirements during an underfrequency disturbance ("f" is the Company System frequency at the Point of Interconnection): **[THESE VALUES MAY BE CHANGED BY THE COMPANY UPON COMPLETION OF THE IRS]**

f ≥ 57.0 Hz	The Facility remains connected to the Company System.

56.0 Hz ≤ f < 57.0 Hz	The Facility may initiate disconnection from the Company System if frequency remains in this range for more than 6 seconds.
f < 56.0 Hz	The Facility may initiate disconnection from the Company System immediately.

(J) Overfrequency ride-through And Disconnection Requirements

The Facility will behave as specified below for overfrequency conditions("f" is the Company System frequency at the Point of Interconnection): **[THESE VALUES MAY BE CHANGED BY THE COMPANY UPON THE COMPLETION OF THE IRS]**

f ≥ 61.5 Hz	The Facility remains connected to the Company System.
61.5 Hz < f ≤ 63.0 Hz	The Facility will initiate disconnection from the Company System or begin an immediate reduction in Actual Output if frequency remains in this range for more than 6 seconds.
f ≥ 63.0 Hz	The Facility will initiate disconnection from the Company System immediately.

(K) Voltage Flicker

Any voltage flicker at the Point of Interconnection caused by the Facility shall not exceed the limits defined by the "Borderline of Visibility Curve" identified in IEEE Standard 519-1992, or latest version "Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems".

(L) Harmonics

Harmonic distortion at the Point of Interconnection caused by the Facility shall not exceed the limits stated in IEEE Standard 519-1992, or latest version

"Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems". Seller shall be responsible for the installation of any necessary controls or hardware to limit the voltage and current harmonics generated from the Facility to defined levels.

(M) Frequency Regulation

Seller shall provide a droop response consistent with the droop response of the system as determined by Company (typically 4% or 5% droop) in the event of a system overfrequency disturbance. The droop characteristic will be verified during the testing of the Facility and based on the type of generation being proposed. The Facility shall have the capability to set droop response as specified by the Company.

4. Maintenance of Seller-Owned Interconnection Facilities

(A) Seller must address any Disconnection (as defined below) according to the requirements of this Section 4 (Maintenance of Seller-Owned Interconnection Facilities) of Attachment B (Facility Owned by Seller). For this purpose, a Disconnection is a disconnection from Company System of at least [redacted] MW **[TO BE DETERMINED BY THE COMPANY UPON COMPLETION OF THE IRS]** from the Facility over a "rolling 120-second period", if such disconnection is due to a defect in or a failure of Seller-Owned Interconnection Facilities. A "rolling 120-second period" means a period that is comprised of 120 seconds and such rolling period will change as each new one (1) second elapses. With the elapse of each new one (1) second, the newest one (1) second would be added to the 120-second period, and the oldest one (1) second would no longer be included in the rolling 120-second period.

(B) For every disconnection from the Company System of at least [redacted] MW **[TO BE DETERMINED BY THE COMPANY UPON COMPLETION OF THE IRS]** from Facility over a rolling 120-second period ("Disconnection Event"), Seller shall investigate the cause of the Disconnection Event, and determine if it is a Disconnection as defined in Section 4(A) of this Attachment B (Facility Owned by Seller). Within three (3) Business Days of the Disconnection Event, Seller shall provide, in writing to Company, an incident report that summarizes the sequence of events and probable cause of the Disconnection Event, and

states whether the Seller believes the Disconnection Event is a Disconnection.

(C) Within forty-five (45) calendar Days of a Disconnection, Seller shall provide, in writing to Company, Seller's findings, data relied upon for such findings, and proposed actions to prevent reoccurrence of a Disconnection ("Proposed Actions"). Company may assist Seller in determining the causes of and recommendations to remedy or prevent a Disconnection ("Company's Recommendations"). Seller shall implement such Proposed Actions (as modified to incorporate the Company's Recommendations, if any) and Company's Recommendations (if any) in accordance with the time period agreed to by the Parties.

(D) In the event Seller and Company disagree as to (i) whether a Disconnection Event occurred, (ii) the sequence of events and/or probable cause of the Disconnection Event, (iii) whether the Disconnection Event is a Disconnection, (iv) the Proposed Actions, (v) Company's Recommendations, and/or (vi) the time period to implement the Proposed Actions and/or Company's Recommendations, then the Parties shall follow the procedure set forth in Section 5 (Expedited Dispute Resolution) of this Attachment B (Facility Owned by Seller).

(E) Upon the fourth (4th) Disconnection (and each subsequent Disconnection) within any Contract Year, the Parties shall follow the procedures set forth in Section 4(B) and Section 4(D) of Attachment B (Facility Owned by Seller), to the extent applicable. If after following the procedures set forth in this Section 4 (Maintenance of Seller-Owned Interconnection Facilities) of Attachment B (Facility Owned by Seller), Seller and Company continue to have a disagreement as to (1) the probable cause of the Disconnection, (2) the Proposed Actions, (3) the Company's Recommendations, and/or (4) the time period to implement the Proposed Actions and/or the Company's Recommendations, then the Parties shall commission a study to be performed by a qualified independent Third-Party consultant ("Qualified Consultant") chosen from the Qualified Independent Third-Party Consultants List ("Consultants List") attached to the Agreement as Attachment D (Consultants List). Such study shall review the design of, review the operating and maintenance procedures dealing with,

recommend modifications to, and determine the type of maintenance that should be performed on Seller-Owned Interconnection Facilities ("Study"). Seller and Company shall each pay for one-half of the total cost of the Study. The Study shall be completed within ninety (90) Days from such fourth Disconnection (and each subsequent Disconnection) within any Contract Year, unless otherwise agreed to in writing by Seller and Company. The Qualified Consultant shall send the Study to Company and Seller. Seller (and/or its Third-Party consultants and contractors), at Seller's expense, shall change the design of, change the operating and maintenance procedures dealing with, implement modifications to, and/or perform the maintenance on Seller-Owned Interconnection Facilities recommended by the Study. Such design changes, operating and maintenance procedure changes, modifications, and/or maintenance shall be completed no later than forty-five (45) Days from the Day the completed Study is issued by the Qualified Consultant, unless otherwise agreed to in writing by Company. In the event the time requirement for the (i) commissioning of the Study, (ii) completion of the Study, or (iii) completion of the design change, operating and maintenance procedure change, modifications, and/or maintenance recommended by the Study is not achieved, Company may limit the total Allowed Capacity to [redacted] MW for the period that such requirement has not been achieved. Nothing in this provision shall affect Company's right to curtail the Facility as provided for in this Agreement.

(F) The Consultants List attached hereto as Attachment D (Consultants List)contains the names of engineering firms which both Parties agree are fully qualified to perform the Study. At any time, except when a Study is being conducted, either Party may remove a particular consultant from the Consultants List by giving written notice of such removal to the other Party. However, neither Party may remove a name or names from the Consultants List without approval of the other Party if such removal would leave the list without any names. Intended deletions shall be effective upon receipt of notice by the other Party, provided that such deletions do not leave the Consultants List without any names. Proposed additions to the Consultants List shall automatically become effective thirty (30) Days after notice is received by the other Party unless written

objection is made by such other Party within said thirty (30) Day period. By mutual agreement between the Parties, a new name or names may be added to the Consultants List at any time.

5. Expedited Dispute Resolution

If there is a disagreement between Company and Seller regarding (i) Seller's compliance with the standards set forth in Section 3 (Performance Standards) of this Attachment B (Facility Owned by Seller), and/or (ii) Section 4 (Maintenance of Seller-Owned Interconnection Facilities)of this Attachment B (Facility Owned by Seller) such as (aa) whether a Disconnection Event occurred, (bb) the sequence of events and/or probable cause of the Disconnection Event, (cc) whether the Disconnection Event is a Disconnection, (dd) the Proposed Actions, (ee) the Company's Recommendations, and (ff) the time period to implement the Proposed Actions and/or the Company's Recommendations, then authorized representatives from Company and Seller, having full authority to settle the disagreement, shall meet in Hawaii (or by telephone conference) and attempt in good faith to settle the disagreement. Unless otherwise agreed in writing by the Parties, the Parties shall devote no more than five (5) Business Days to settle the disagreement in good faith. In the event the Parties are unable to settle the disagreement after the expiration of the time period, then either Party may pursue the dispute resolution procedure set forth in Article 28 (Dispute Resolution) of this Agreement.

6. Modeling

Seller shall provide all of the data to allow the modeling of the generators, transformers and control systems within the Facility. Seller shall validate or update the modeling data as requested by Company.

7. Testing Requirements

Seller shall coordinate periodic testing of the Facility with Company to ensure that the Facility is meeting the performance standards specified under this Agreement. Immediately following the initial connection of the Facility, Seller shall test the voltage regulation capability, reactive power response, reactive power capability, harmonic and flicker limits, and any other testing as determined by Company.

8. Data and Forecasting

Seller shall provide data and/or a power forecast in accordance with the terms of Article 6 (Forecasting) of this Agreement.

9. Technology Specific Requirements:

(A) Three-Phase Synchronous Generators:

The generating facility circuit breakers shall be 3-phase devices with electronic or electromechanical control. The Seller shall be responsible for properly synchronizing its generating facility with the Company System by means of either a manual or automatic synchronizing function. Automatic synchronizing is required for all synchronous generators which have an SCCR greater than 5%. For a generating facility whose SCCR exceeds 5%, the Facility shall provide protective equipment suitable for detecting loss of synchronism and automatically disconnecting the generating facility from the Company System. Unless otherwise agreed to between the Company and Seller, synchronous generators shall automatically regulate power factor, not voltage, while operating in parallel with the Company System.

(B) Induction Generators:

(i) Induction generators may be connected and brought up to synchronous speed (as an induction motor) if it can be demonstrated that the initial voltage drop measured at the Point of Interconnection is within the visible flicker limits as defined by IEEE 519-1992 (or latest version). The same requirements also apply to induction generation connected at or near synchronous speed because a similar voltage dip is present due to an inrush magnetizing current. The Facility shall submit number of starts per specific time period and maximum starting kVA draw data for the utility to verify that the voltage dip due to starting is within the visible flicker limits and does not degrade the normal voltage provided by the utility.

(ii) Induction generators do not require separate synchronizing equipment. Starting or rapid load fluctuations on induction generators can

adversely impact the Company System voltage. Corrective step-switched capacitors or other techniques may be necessary if the voltage fluctuations measured at the Point of Interconnection are not within the visible flicker limits as defined by IEEE 519-1992 (or latest version). These measures can, in turn, cause ferroresonance. If these measures (additional capacitors) are installed on Seller's side of the Point of Interconnection, the Company will review these measures and may require Seller to install additional protective relaying equipment. Company will determine whether additional equipment is required to protect the Company System.

(C) Inverter Systems:

(i) Direct current generators and non-power (i.e. other than 60 Hertz) alternating current generators can only be installed in parallel with the Company System using a non-islanding synchronous inverter. The design shall comply with the requirements of IEEE Std 1547-2003 (or latest version) such that the synchronous inverter will automatically disconnect upon an interruption on the Company System.

(ii) Self-commutated inverters of the Company-interactive type shall synchronize to the Company System. Inverters capable of stand-alone operation shall not attempt to control the voltage while operating in parallel with the Company System. Line-commutated, thyristor-based inverters are not recommended and will require additional technical study to determine harmonic and reactive power requirements. All interconnected inverter systems shall comply with the harmonic current limits of IEEE Std 519-1992 (or latest version).

ATTACHMENT C
METHODS AND FORMULAS FOR MEASURING PERFORMANCE STANDARDS

1. Performance Standards as defined below shall be used, in part, to govern actions by Company to curtail the electric output of the Facility for purposes of maintaining power quality on Company System. Specific standards are defined for:

- Ramp Rate (RR)
- Instantaneous Power Fluctuation Rate
- Sub-minute Power Fluctuation Rate

2. Formulas for measuring the performance standards are presented below, and assume that the power fluctuations will be monitored on the SCADA/EMS system. These formulas are based on the periodicity at which analog data is retrieved from the RTU. This periodicity is called the "scan rate". Company presently uses a two-second analog scan rate. The formulas below are based on the two-second scans. **[FOR WIND PROJECTS ADD: The transducer used to obtain the instantaneous power (MW) output from a wind farm is accurate to +/- 0.1%]**. The two-second scan rate, characteristics of transducers and RTU reporting, and SCADA method of calculation, were considered and included in the proposed values for the performance standards.

3. Ramp Rate Calculation:

$$RR = \left| MW_{s-30} - MW_s \right|$$

Where:

RR = Ramp Rate, may be calculated once every scan

MW_{s-30} = The instantaneous MW analog value 30 scans (60 seconds) prior the present scan

MW_s = The instantaneous MW analog value for the present scan

4. Power Fluctuation Rate Calculations:

a. Instantaneous

$$I = \left| MW_{s-1} - MW_s \right|$$

Where:

I = Instantaneous Power Change, calculated once every scan

MW_{s-1} = The instantaneous MW analog value for the previous scan

MW_s = The instantaneous MW analog value for the present scan

b. Subminute Average:

$$A_1 = \frac{\sum_{s=1}^{30} |MW_{s-1} - MW_s|}{30}$$

Where:

A_1 = Subminute Average, calculated once every 30 scans

MW_{s-1} = The instantaneous MW analog value for the previous scan

MW_s = The instantaneous MW analog value for the present scan

ATTACHMENT D
CONSULTANTS LIST

(To be completed prior to the In-Service Date)

ATTACHMENT E
THREE-LINE DRAWING

(To be attached as per Section 1(A) of Attachment B)

ATTACHMENT F
RELAY LIST AND TRIP SCHEME

(To be attached as per Section 1(A) of Attachment B.)

ATTACHMENT G
COMPANY-OWNED INTERCONNECTION FACILITIES

1. Description of Company-Owned Interconnection Facilities

(A) General. Company shall furnish or construct (or may have Seller furnish or construct, in whole or in part), own, operate and maintain all Interconnection Facilities required to interconnect Company System with Facility at [redacted] volts, up to the Point of Interconnection (collectively, the "Company-Owned Interconnection Facilities").

(B) Site. Where any Company-Owned Interconnection Facilities are to be located on the Site, Seller shall provide, at no expense to Company, a location and access acceptable to Company for all such Company-Owned Interconnection Facilities, as well as an easement, license or right of entry to access such Company-Owned Interconnection Facilities. If power sources (120/240VAC) are required, Seller shall provide such sources, at no expense to Company.

(C) IRS. An IRS addressing Facility requirements was completed for the project in accordance with the IRS Letter Agreement, and the results have been incorporated in this Attachment G (Company-Owned Interconnection Facilities) as appropriate.

(D) Seller's Payment Obligations. Company-Owned Interconnection Facilities, for which Seller has agreed to pay, in accordance with Section 2 (Seller Payment to Company for Company-Owned Interconnection Facilities and Review of Facility) of this Attachment G (Company-Owned Interconnection Facilities), include **[ADD LIST OF COMPANY-OWNED INTERCONNECTION FACILITIES THAT ARE REQUIRED PURSUANT TO THE RESULTS OF THE IRS. THE FOLLOWING IS AN EXAMPLE OF THE TYPES OF FACILITIES THAT COULD BE LISTED]**:

(i) **[Line extension]**;

(ii) Substation additions and/or modifications of Company's existing structures as necessary. This would include but not be limited to protective relaying and setting changes;

(iii) Supervisory control and communications equipment (including but not limited to, SCADA/RTU, microwave, satellite, dedicated phone line(s) and/or any other acceptable communications means (determined by Company), fiber optics, copper cabling, installation of batteries and charger system, etc.);

(iv) Revenue meter support infrastructure;

(v) Any additional Interconnection Facilities needed to be installed as a result of final determination of Facility switching station site, final design of Facility to enable Company to complete the Interconnection Facilities and be compatible with Good Engineering and Operating Practices.

(E) Construction By Seller. Seller (and/or its third Party consultants or contractors (collectively, "Contractors")) will install, test and place in service, at Seller's expense, the **[LIST COMPANY-OWNED INTERCONNECTION FACILITIES TO BE CONSTRUCTED BY SELLER]**.

(F) Coordination of Construction. Prior to Seller engaging the Contractors, Seller shall obtain Company's written approval, which approval shall not be unreasonably withheld. Prior to Seller and/or its Contractors first starting to work on the construction plans for Company-Owned Interconnection Facilities to be constructed by Seller (and/or its Contractors), such as the civil, structural, and construction drawings, specifications to vendors, vendor approved final drawings and materials lists (collectively, the "Plans"),Seller and/or its Contractors shall meet with Company to discuss the construction of such Company-Owned Interconnection Facilities, including but not limited to subjects concerning coordination of construction milestone dates, agreement on areas of interface design, and Company's design/drawing layout and symbols standards, equipment specifications and construction specifications and standards. Company will provide the design and specifications information so Seller can incorporate such information in its bid documents.

(G) Plans. No later than sixty (60) Days before Seller and/or its Contractors first start to order materials and equipment for Company-Owned Interconnection

Facilities to be constructed by Seller and/or its Contractors, Seller shall provide Company with the Plans. The Plans for Company-Owned Interconnection Facilities to be constructed by Seller (and/or its Contractors) shall comply with (i) all applicable Laws; (ii) Company's design/drawing layout and symbol standards, equipment specifications, and construction specifications and standards; and (iii) Good Engineering and Operating Practices (collectively, the "Standards").

(H) Company's Review of the Plans. Unless otherwise agreed to by the Parties, Company shall have thirty (30) Days following receipt of the Plans for it to review and comment on the Plans, and verify in writing to Seller that the Plans comply with the Standards, which verification shall not be unreasonably withheld. If Company reasonably determines that the Plans are not in accordance with the Standards, then it may request in writing a response from Seller to its comments and Seller shall respond in writing within thirty (30) Days of such request by providing (i) its justification for why its Plans conform to the Standards or (ii) changes in the Plans responsive to Company's comments and in accordance with the Standards.

(I) Company Inspection. Construction work will be subject to Company inspections to ensure that construction is done in accordance with the Standards. Company inspectors will be allowed access to the construction sites for inspections and to monitor construction work. The inspector shall have the authority to work with the appropriate construction supervisor to stop any work that does not meet the Standards. All equipment and materials used in Company-Owned Interconnection Facilities to be constructed by Seller and/or its Contractors shall meet the Standards.

(J) Acceptance Test Procedures.

(i) Seller shall provide Company with at least seven (7) Days advance written notice of the Acceptance Test. No electric energy will be delivered from Seller to Company during this Acceptance Test. No later than thirty (30) Days prior to conducting the Acceptance Test, Company and Seller shall agree on a written protocol setting out the detailed procedure and criteria for passing the Acceptance Test. Attachment N

(Acceptance Test General Criteria) provides general criteria to be included in the written protocol for the Acceptance Test. Within fifteen (15) Business Days of successful completion of the Acceptance Test, Company shall notify Seller in writing that the Acceptance Test has been passed and the date upon which the Acceptance Test was passed.

(ii) Company will be present when the Acceptance Test is conducted, and Seller shall timely correct any deficiencies identified during the Acceptance Test. Seller will be responsible for the cost of Company personnel (and/or Company contractors) performing the duties (such as reviewing the Plans and reviewing the construction) necessary for Company-Owned Interconnection Facilities to be constructed by Seller (and/or its Contractors). If Company (i) does not make any inspection or test, (ii) does not discover defective workmanship, materials or equipment, or (iii) accepts Company-Owned Interconnection Facilities (that were constructed by Seller and or its Contractors), such action or inaction shall not relieve Seller from its obligation to do and complete the work in accordance with the Plans approved by Company.

2. Seller Payment to Company for Company-Owned Interconnection Facilities and Review of Facility

(A) Seller Payment to Company

(i) For Company-Owned Interconnection Facilities to be designed, engineered and constructed by Company, Seller shall pay the Total Estimated Interconnection Cost which is comprised of the estimated costs of (aa) acquiring and installing such Company-Owned Interconnection Facilities, (bb) the engineering and design work (including but not limited to Company, affiliated Company and contracted engineering and design work) associated with (i) developing such Company-Owned Interconnection Facilities and (ii) reviewing and specifying those portions of Facility which allow interconnected operations as such are described in Attachment B(Facility Owned by Seller), and (cc) conducting the Acceptance Test and Control

System Acceptance Test. The Total Actual Interconnection Cost (the actual cost of items (aa) through (cc)), together with the cost of the IRS (which will be paid pursuant to the IRS Letter Agreement), are the "Total Interconnection Cost".

(ii) Summary List of Company-Owned Interconnection Facilities and Related Services:

[THIS LIST SHOULD GENERALLY INCORPORATE THE LIST IN ATTACHMENT G, SECTION 1(D), PLUS TESTING.]

(iii) The following summarizes the Total Estimated Interconnection Cost:

[THIS LIST SHOULD INCLUDE ESTIMATED COSTS FOR THE ITEMS LISTED IN ATTACHMENT G, SECTION 2(A)(ii).]

The Total Estimated Interconnection Cost is $_____.

(B) Total Estimated Interconnection Costs. The Total Estimated Interconnection Cost, which, except as otherwise provided herein, is non-refundable, shall be paid in accordance with the following schedule:

(i) On the Execution Date, $10,000.00 is due and payable by Seller to Company;

(ii) Thirty (30) Days after the Execution Date, the additional amount in excess of $10,000.00, up to that portion of the Total Estimated Interconnection Cost described in Section 2(a)(i)(B) of this Attachment G (Company-Owned Interconnection Facilities), is due and payable by Seller to Company;

(i) Company shall not be obligated to perform engineering and design work on Company-Owned Interconnection Facilities until Seller pays the amounts in Section 2(B)(i) and Section 2(B)(ii) of this Attachment G (Company-Owned Interconnection Facilities); and

(iii) Fourteen (14) Days after receipt of an invoice from Company, which shall be provided not less than thirty (30) Days prior to start of procurement of Company-Owned Interconnection

Facilities, the difference between the portion of the Total Estimated Interconnection Cost paid to date and the Total Estimated Interconnection Cost is due and payable by Seller to Company.

(i) Company shall not be obligated to procure and construct Company-Owned Interconnection Facilities until Seller pays the amount in Section 2(B)(iii) of this Attachment G (Company-Owned Interconnection Facilities).

(C) True-Up. Within thirty (30) Days of the final accounting, which shall take place within thirty (30) Days of completion of construction of Company-Owned Interconnection Facilities, Seller shall remit to Company the difference between the Total Estimated Interconnection Cost paid to date and the Total Actual Interconnection Cost, which is the final accounting of the Total Interconnection Costs. If in fact the Total Actual Interconnection Cost is less than the payments received by Company as the Total Estimated Interconnection Cost, Company shall repay the difference to Seller within thirty (30) Days of the final accounting.

(D) Termination of the Agreement. If any Event of Default by Seller occurs such that termination of the Agreement results, or as otherwise provided herein, Seller shall pay to Company the actual costs and cost obligations reasonably incurred by Company for Company-Owned Interconnection Facilities as of the date the Agreement is terminated. Such payment shall be made within thirty (30) Days of receipt of an invoice from Company.

(E) Ownership. All Company-Owned Interconnection Facilities including those portions, if any, provided, or provided and constructed, by Seller shall be the property of Company.

3. Ongoing Operation and Maintenance Charges

(A) Prior to the Transfer Date. Seller shall operate and maintain, at its cost, Company-Owned Interconnection Facilities that it or its Contractors constructed, if any, prior to the Transfer Date.

(B) On or After the Transfer Date. On and after the Transfer Date, Company shall own, operate and maintain Company-Owned Interconnection Facilities.

(C) Monthly Bill. Company shall bill Seller monthly for any costs incurred in operating, maintaining and replacing (to the extent not covered by insurance) Company-Owned Interconnection Facilities. Company's costs will be determined on the basis of, but not limited to, direct payroll, material costs, applicable overheads at the time incurred, consulting fees and applicable taxes. Seller shall, within thirty (30) Days after the billing date, reimburse Company for such monthly billed operation and maintenance charges.

4. Relocation of Company-Owned Interconnection Facilities

Company shall bill Seller for any costs incurred in relocating Company-Owned Interconnection Facilities in the event that the applicable Land Rights include a relocation clause and such clause is exercised or if Company-Owned Interconnection Facilities must be relocated for any other reason not caused by Company. Seller shall, within thirty (30) Days after the billing date, reimburse Company for such billed relocation charges.

5. Guarantee for Interconnection Costs

(A) Standby Letter of Credit. To ensure that Company is paid by Seller for Company-Owned Interconnection Facilities to be provided and/or constructed by Company described in Section 2 (Seller Payment to Company for Company-Owned Interconnection Facilities and Review of Facility) of this Attachment G (Company-Owned Interconnection Facilities), Seller shall obtain an Irrevocable Standby Letter of Credit with no Documentary Requirement ("Standby Letter of Credit"), wherein Company shall receive payment from the bank upon request by Company.

(B) Requirements of the Standby Letter of Credit. The Standby Letter of Credit shall be (i) at least in the amount of twenty-five percent (25%) of the Total Estimated Interconnection Cost, (ii) issued by a bank in Hawaii which is reasonably acceptable to Company, and (iii) in form and substance reasonably acceptable to Company. The Standby Letter of Credit shall be effective from the earlier of (aa) thirty (30) Days

following the Execution Date, or (bb) the date that Seller requests Company to order equipment or commence construction on Company-Owned Interconnection Facilities. The Standby Letter of Credit shall be in effect through the earlier of forty-five (45) Days after the final accounting or seventy-five (75) Days after the Contract is terminated. Seller shall provide to Company within fourteen (14) Days of the date the Standby Letter of Credit is to be effective as aforesaid, a document from the bank which indicates that such a Standby Letter of Credit has been established.

(C) Other Form of Security. Notwithstanding the foregoing, in lieu of a Standby Letter of Credit, Seller may provide such other form of security as is agreed to by Company in writing.

6. Land Restoration

(A) Definition of "Land". For the purposes of this Attachment G (Company-Owned Interconnection Facilities), "Land" means the Site and any other real property where any Company-Owned Interconnection Facilities are located.

(B) Removal of Interconnection Facilities. After termination of this Agreement, Seller shall, at its expense, remove all (i) Company-Owned Interconnection Facilities from the Land and (ii) Seller-Owned Interconnection Facilities from the Land, as designated by Company; provided, however, that, Company may elect to remove all or part of the Company-Owned Interconnection Facilities and/or Seller-Owned Interconnection Facilities from the Land because of operational concerns over the removal of such Interconnection Facilities, in which case Seller shall reimburse Company for its costs to remove such Company-Owned Interconnection Facilities and/or Seller-Owned Interconnection Facilities.

(C) Restoration of the Land. After the termination of this Agreement, Seller shall, at its expense, restore the Land to its condition prior to construction of such Company-Owned Interconnection Facilities or Seller-Owned Interconnection Facilities. Land restoration shall be completed within ninety (90) Days of termination of this Agreement, or as otherwise agreed to by both Parties in writing.

7. Transfer of Ownership/Title

(A) Transfer of Ownership and Title. On the Transfer Date, Seller shall transfer to Company all right, title and interest in and to Company-Owned Interconnection Facilities to the extent such facilities were designed and constructed by Seller and/or its Contractors. In connection with the transfer of Company-Owned Interconnection Facilities, Seller shall transfer and assign to Company all applicable manufacturers' or Contractors' warranties which are assignable. Seller shall provide a written list of the manufacturers' and Contractors' warranties which will be assigned to Company and the expiration dates of such warranties no later than thirty (30) Days before the Transfer Date.

(B) No Liens or Encumbrances. Company's title to and ownership of Company-Owned Interconnection Facilities that were designed and constructed by Seller and/or its Contractors shall be free and clear of liens and encumbrances.

(C) Land Rights. In connection with the transfer of Company-Owned Interconnection Facilities to Company, Seller shall grant, transfer or assign to Company, such Land Rights, necessary to operate and maintain Company-Owned Interconnection Facilities on and after the Transfer Date.

(D) Form of Documents. The transfers to be made to Company pursuant to this Section 7 (Transfer of Ownership/Title) of Attachment G (Company-Owned Interconnection Facilities) shall not require any further payment by Company. The form of the document to be used to convey title to the Company-Owned Interconnection Facilities that were designed and constructed by or on behalf of Seller shall be substantially in the form set forth in Attachment H (Form of Bill of Sale and Assignment). The form of the document(s) to be used to assign leases shall be substantially in the form set forth in Attachment I (Form of Assignment of Lease and Assumption). To the extent Land Rights other than leases are transferred to Company, appropriate modifications will be made to Attachment I (Form of Assignment of Lease and Assumption) to effectuate the transfer of such Land Rights.

8. Government Approvals for Any Company-Owned Interconnection Facilities Constructed by Seller

Seller shall obtain all required permits, licenses, approvals, certificates, entitlements and other authorizations issued by Governmental Authorities (the "Government Approvals") required to construct, own, operate and maintain the Company-Owned Interconnection Facilities that Seller and/or its Contractors will construct and shall provide these prior to the Transfer Date. On or before the Transfer Date, Seller shall provide Company with (i) copies of all such Governmental Approvals obtained by Seller regarding the construction, ownership, operation and maintenance of Company-Owned Interconnection Facilities that Seller and/or its Contractors constructed and (ii) documentation that all such Governmental Approvals have been closed with the issuing Governmental Authority.

9. Land Rights

Seller shall obtain all Land Rights for the Land which are required to construct, maintain and operate the Company-Owned Interconnection Facilities. Seller shall use commercially reasonable efforts to obtain perpetual Land Rights. Such Land Rights shall contain terms and conditions which are acceptable to Company and shall be provided in advance to Company for its review. For so long as Seller has the right under this Agreement to sell electric energy to Company, Seller shall pay for any rents and other payments due under such Land Rights that are associated with Company-Owned Interconnection Facilities.

10. Contracts for Company-Owned Interconnection Facilities

For all contracts entered into by or on behalf of Seller for Company-Owned Interconnection Facilities to be designed, engineered and constructed, in whole or in part, by or on behalf of Seller, the following shall apply: (i) Company shall be made an intended third-party beneficiary of such contracts; and (ii) Company shall be provided with copies of such executed contracts, including the commercial terms.

ATTACHMENT H
BILL OF SALE AND ASSIGNMENT

THIS BILL OF SALE AND ASSIGNMENT ("Bill of Sale"), made as of the ____ day of _____, 20___, by _____ ("Transferor") and _____ ("Transferee").

W I T N E S S E T H:

1. Bill of Sale. In consideration of TEN DOLLARS ($10.00) and other good and valuable consideration paid to Transferor by Transferee, the receipt and sufficiency of which are hereby acknowledged, Transferor does hereby sell, assign and transfer over to Transferee all of Transferor's right, title and interest, in and to (i) all the tangible personal property and fixtures (including but not limited to the items set forth in Schedule H-1 (Description of Tangible Personal Property and Fixtures) attached hereto and incorporated herein), that constitutes what is referred to as the "Company-Owned Interconnection Facilities to be installed by or on behalf of Seller" (or words to similar effect) as set forth in Attachment G (Company-Owned Interconnection Facilities) to the Power Purchase Agreement for As-Available Renewable Energy dated _____, 20___ between **[Transferor and Transferee]** and (ii) the intangible personal property (including but not limited to the intangible personal property set forth in Schedule H-2 (Description of Intangible Personal Property)attached hereto and incorporated herein) owned by Transferor and used or to be used in the ownership, operation and maintenance of the aforesaid tangible personal property, to the extent assignable by Transferor, including without limitation, certificates of occupancy, permits, licenses, transferable warranties and guaranties, instruments, documents of title, and general intangibles pertaining to the aforesaid tangible personal property.

2. Warranty of Title. Transferor hereby warrants to Transferee that Transferor is the legal owner of the aforesaid tangible personal property and the aforesaid intangible personal property (including but not limited to the property set forth in Schedule H-1 (Description of Tangible Personal Property and Fixtures)and Schedule H-2 (Description of Intangible Personal Property)), and that said property is being sold, assigned and transferred to Transferee free and clear of all liens and encumbrances.

3. Governing Law. This Bill of Sale shall be governed by, and construed and interpreted in accordance with, the laws of the State of Hawaii.

[Signatures for Bill of Sale and Assignment]

IN WITNESS WHEREOF, Transferor and Transferee have executed this instrument on the day and year first above written.

_____,
a _____

By_____
Its_____

"Transferor"

_____,
a Hawaii corporation

By_____
Its

By_____
Its

"Transferee"

SCHEDULE H-1

DESCRIPTION OF
TANGIBLE PERSONAL PROPERTY AND FIXTURES

SCHEDULE H-2

DESCRIPTION OF INTANGIBLE PERSONAL PROPERTY

LAND COURT SYSTEM | REGULAR SYSTEM

Return by Mail ( ) Pickup ( ) To:

Tax Map Key Nos.: Total pages: _____

ATTACHMENT I
ASSIGNMENT OF LEASE AND ASSUMPTION

THIS ASSIGNMENT is made as of this _____ day of _____, 20___, by _____, a _____, whose principal place of business and post office address is _____, hereinafter called the "Assignor," and _____, a Hawaii corporation, whose principal place of business and post office address is _____, Honolulu, HI 968___, hereinafter called the "Assignee",

W I T N E S S E T H:

THAT the Assignor, for and in consideration of the sum of TEN DOLLARS ($10.00) and other good and valuable consideration to it paid by the Assignee, the receipt and sufficiency of which are hereby acknowledged, and of the covenants and agreements of the Assignee hereinafter contained and on the part of the Assignee to be faithfully kept and performed, does hereby sell, assign, delegate, transfer, set over and deliver unto the Assignee, and its successors and assigns, all of Assignor's right, title and interest in and to the lease described in Schedule 1 (the "Lease"); together with

all interests thereto appertaining, and together with the personal property located on the land thereby demised.

And all of the estate, right, title and interest of the Assignor in and to the land thereby demised, and all buildings, improvements, rights, easements, privileges and appurtenances thereunto belonging or appertaining or used, occupied and enjoyed in connection with said Lease and the land thereby demised.

TO HAVE AND TO HOLD the same unto Assignee and its successors and assigns, for and during the respective unexpired term of said Lease, and as to said personal property (if any) absolutely and forever.

AND, in consideration of the premises, the Assignor does hereby covenant with the Assignee that the Assignor is the lawful owner of the herein described real property; that said Lease is in full force and effect and is not in default; that said real property is free and clear of and from all liens and encumbrances, except for the lien of real property taxes not yet by law required to be paid; that the Assignor is the lawful owner of said personal property (if any) and that Assignor's title thereto is free and clear of and from all liens and encumbrances, that the Assignor has good right to sell and assign said real property and personal property (if any) as aforesaid; and, that the Assignor will WARRANT AND DEFEND the same unto the Assignee against the lawful claims and demands of all persons, except as aforesaid.

AND, in consideration of the foregoing, the Assignee does hereby promise, covenant and agree to and with the Assignor and to and with said Lessor, that the Assignee will, effective as of and from the date of the execution and delivery of this instrument and during the residue of the term of said Lease, pay the rents thereby reserved as and when the same become due and payable pursuant to the provisions of said Lease, and will also faithfully observe and perform all of the covenants and conditions contained in said Lease which from and after the date hereof are or ought to be observed and performed by the lessee therein named, and will at all times hereafter indemnify and save harmless the Assignor from and against the nonpayment of said rent and the nonobservance or nonperformance of said covenants and conditions and each of them.

The terms "Assignor" and "Assignee", as and when used herein, or any pronouns used in place thereof, shall mean and include the masculine, feminine or neuter, the singular or

plural number, individuals, partnerships, trustees or corporations and their and each of their respective successors, heirs, personal representatives, successors in trust and assigns, according to the context hereof. All covenants and obligations undertaken by two or more persons shall be deemed to be joint and several unless a contrary intention is clearly expressed elsewhere herein. The term "Lease", as and when used herein, means the lease or sublease demising the leasehold estate described in Schedule 1, together with all recorded amendments thereof, if any, whether or not listed in Schedule 1. The term "rent", as and when used herein, means and includes all rents, taxes, assessments and any other sums charged pursuant to the Lease.

This instrument may be executed in any number of counterparts, each of which shall be deemed an original, but all of which shall constitute one instrument binding on all the Parties hereto, notwithstanding that all the Parties are not signatory to the original or the same counterpart.

[Signatures for Assignment of Lease and Assumption are on following page.]

IN WITNESS WHEREOF, Company and Assignor have executed this instrument as of the date first above written.

_____

By_____
Name:
Title:

By_____
Name:
Title:

"Assignor"

_____

By_____
Name:
Title:

By_____
Name:
Title:

"Assignee"

STATE OF HAWAII)
) SS:
CITY AND COUNTY OF HONOLULU)

On this ____ day of _____, 200__, before me personally appeared _____ and _____, to me known to be the persons described in and who executed the foregoing instrument, and acknowledged that such persons executed such instrument as the free act and deed of such persons and if applicable in the capacity shown, having been duly authorized to execute such instrument in such capacity.

Signature: _____

(Official Stamp or Seal)

Print Name: _____
Notary Public, State of Hawaii

My commission expires: _____

NOTARY CERTIFICATION STATEMENT

Document Identification or Description:

Assignment of Lease and Assumption

Doc. Date: _____ No. of Pages: _____

Jurisdiction: _____ Circuit
(in which notarial act is performed

_____ _____ (Official Stamp or Seal)
Signature of Notary Date of Notarization and Certification Statement

_____
Printed Name of Notary

STATE OF HAWAII)
) SS:
CITY AND COUNTY OF HONOLULU)

On this ____ day of _____, 200__, before me personally appeared _____ and _____, to me known to be the persons described in and who executed the foregoing instrument, and acknowledged that such persons executed such instrument as the free act and deed of such persons and if applicable in the capacity shown, having been duly authorized to execute such instrument in such capacity.

Signature: _____

(Official Stamp or Seal)

Print Name: _____
Notary Public, State of Hawaii

My commission expires: _____

NOTARY CERTIFICATION STATEMENT

Document Identification or Description:

Assignment of Lease and Assumption

Doc. Date: _____ No. of Pages: _____

Jurisdiction: _____ Circuit
(in which notarial act is performed

_____ _____ (Official Stamp or Seal)
Signature of Notary Date of Notarization and Certification Statement

_____
Printed Name of Notary

SCHEDULE 1

Description of Lease
To Be Attached

ATTACHMENT J
ENERGY PURCHASES BY COMPANY

1. Price for Purchase and Rate of Delivery. Subject to the provisions of this Agreement, Company shall accept and pay for Actual Output at the applicable rates set forth in the Schedule FIT Tier 3 beginning on the In-Service Date. Provided, however, that in any Contract Year, if the Actual Output for such Contract Year is in excess of 120% of the Annual Contract Energy for such Contract Year (as determined pursuant to Section 2.2 (Payments for Actual Output) of the Agreement), the price paid for electric energy in excess of such Annual Contract Energy shall be 75% of the otherwise applicable Contract Price for such electric energy.

2. Test Energy. Company shall use reasonable efforts to accept test energy that is delivered as part of the normal testing for generators (such as energy delivered to Company during the Control System Acceptance Test but not during the Acceptance Test), provided Seller shall use reasonable efforts to coordinate such normal testing with Company so as to minimize adverse impacts on the Company System and operations. Company shall compensate Seller for test energy as provided in Section 2.5 (Payments Prior to In-Service Date)of the Agreement

ATTACHMENT K
GUARANTEED PROJECT MILESTONES

Guaranteed Project Milestone Date	**Description of Each Guaranteed Project Milestone**
[Date]	Guaranteed In-Service Date

ATTACHMENT L
REPORTING MILESTONES

Reporting Milestone Date	**Description of Each Reporting Milestone**
[Date]	Permit Application Filing Date (as defined in the Definitions section of the Agreement).
[Date]	Seller shall provide Company with a copy of the executed Facility equipment, engineering, procurement and construction ("EPC"), or other general contractor, agreements.
[Date]	Seller shall provide Company with copies of executed purchase orders/contracts for the delivery and installation of Facility turbine(s)/generator(s) and the step-up transformer(s).
[Date]	Seller shall provide Company with copies, as applicable, of executed Facility operating agreements, ***[electric transmission and/or interconnection agreements (?).]***
[Date]	Seller shall provide Seller with documentation that all governmental Permits have been obtained or will be obtained by the time needed to meet all Construction Milestones.
[Date]	Seller shall provide Company with documentation of having achieved closing on financing for the Facility or provided Company with proof of financial capability to construct the Facility. ("Construction Financing Closing Milestone").

[Date]	Construction Start Date (as defined in the Definitions section of the Agreement).
[Date]	Seller shall have laid the foundation for all Facility buildings, generating facilities and step-up transformer facilities.
[Date]	The turbine(s)/generator(s) shall have been installed at the Site.
[Date]	The step-up transformer shall have been installed at the Site.
[Date]	Seller shall have constructed Seller's Interconnection Facilities and such facilities are capable of being energized.
[Date]	The Acceptance Test of the Facility commences.

ATTACHMENT M
FORM OF LETTER OF CREDIT

[Bank Letterhead]

[Date]

Beneficiary: [Hawaiian Electric Company
Address]

[Bank's Name]
[Bank's Address]

Re: **[Beneficiary's Name]**
[Beneficiary's Address]

We hereby establish, in your favor, our irrevocable Letter of Credit Number _____ for the account of **[Applicant's Name]** and **[Applicant's Address]** in the initial amount of $_____ **[dollar value]** and authorize you, Hawaiian Electric Company ("Beneficiary"), to draw at sight on **[Bank's Name]**.

Subject to the terms and conditions hereof, this Letter of Credit secures **[Account Party]**'s certain obligations to Beneficiary under the Power Purchase Agreement dated as of _____ between **[Account Party]** and Beneficiary.

Partial draws of this Letter of Credit are permitted. This Letter of Credit is not transferable. Drafts on us at sight shall be accompanied by a Beneficiary's signed statement signed by a representative of Beneficiary substantially as follows:

> The undersigned hereby certifies that (i) I am duly authorized to execute this document on behalf of Hawaiian Electric Company, and (ii) the amount of the draft accompanying this certification is due and owing to Hawaiian Electric Company under the terms of the Power Purchase Agreement dated as of _____, between _____, and Hawaiian Electric Company.

The amounts of any drafts drawn under this credit are to be endorsed on the reverse side hereof. Such drafts must bear the clause "Drawn under **[Bank's Name and Letter of Credit Number _____ and date of Letter of Credit.]**"

This letter of credit shall expire one year from the date hereof. Notwithstanding the foregoing, however, this letter of credit shall be automatically extended (without amendment of any other term and without the need for any action on the part of the undersigned or Beneficiary) for one year from the initial expiration date and each future expiration date unless we notify you in writing at least thirty (30) days prior to any such expiration date that this letter of credit will not be so extended. Any such notice shall be delivered by registered or certified mail, or by FedEx, both to **[name and address of Beneficiary's Purchased Power Group contact]**, and to **[name and address of Finance Department contact]**.

We hereby agree with drawers that drafts and documents as specified above will be duly honored upon presentation to **[Bank's Name]** and **[Bank's Address]** if presented on or before the then-current expiration date hereof.

Payment of any amount under this Letter of Credit by **[Bank]** shall be made as the Beneficiary shall instruct on the next Business Day after the date the **[Bank]** receives all documentation required hereunder, in immediately available funds on such date.

Unless otherwise expressly stated herein, this irrevocable standby letter of credit is issued subject to the Uniform Customs and Practice for Documentary Credits, 1993 revision, International Chamber of Commerce publication no. 500.

[Bank's Name]:

By: _____
[Authorized Signature]

ATTACHMENT N
ACCEPTANCE TEST GENERAL CRITERIA

[THIS ATTACHMENT WILL NEED TO BE MODIFIED BASED ON THE TYPE AND DESIGN OF THE FACILITY]

Upon final completion of Company review of the Facility's drawings, final test criteria and procedures shall be agreed upon by Company and Seller no later than thirty (30) Days prior to conducting the Acceptance Test in accordance with the Agreement. The Acceptance Test may include the following:

1. Interconnection:

   (A) Based on manufacturer's specification, test the local operation of the Facility's ____kV breakers, which connect the Facility to Company System - must open and close locally using the local controls. Test and ensure that the status shown on the Energy Management System (EMS) is the same as the actual physical status in the field.

   (B) Remotely test the operation of the Facility's ___kV breakers which connect the Facility to Company System - must open and close remotely from Company's EMS. Test and ensure that the status shown on the EMS is the same as the actual physical status in the field.

   (C) Relay test engineers to connect equipment and simulate certain inputs to test and ensure that the protection schemes such as any under/over frequency and under/over voltage protection or the Direct Transfer Trip operate as designed. (For example, a fault condition may be simulated to confirm that the breaker opens to sufficiently clear the fault. Additional scenarios may be tested and would be outlined in the final test criteria and procedures.) Seller to also test the synchronizing mechanisms to which the Facility would be synchronizing and closing into the Company System to ensure correct operation. Other relaying also to be tested as specified in the protection review of the IRS and on the single line diagram, Attachment E (Three-Line Diagram) for the Facility.

(D) 4) All ___kV breaker disconnects and other high voltage switches will be inspected to ensure they are properly aligned and operated manually or automatically (if designed).

(E) Switching Station inspections - The Switching Station may be inspected to test and ensure that the equipment that Seller has installed is installed and operating correctly based upon agreed-to design. Wiring may be field verified on a sample basis against the wiring diagrams to ensure that the installed equipment is wired properly . The grounding mat at the Switching Station may be tested to make sure there is adequate grounding of equipment.

(F) Communication testing - Communication System testing to occur to ensure correct operation. Detailed scope of testing will be agreed by Company and Seller to reflect installed systems and communication paths to tie the Facility to Company's communications system.

(G) Various contingency scenarios to be tested to ensure adequate operation, including testing contingencies such as loss of communications, and fault simulations to ensure that the Facility's ___kV breakers open as they are designed to open. (Back up relay testing)

2. Witness of Facility protection scheme testing:

(A) Company may have someone on-site when Seller performs any testing dealing with Seller's protection schemes such as any under/over voltage or under/over frequency protection schemes to ensure they meet the performance requirements of this Agreement and the IRS.

3. Telephone Communication

(A) Test to confirm Company has a direct line to the Facility control room at all times and that it is programmed correctly.

(B) Test to confirm that the Facility operators can sufficiently reach Company System Operator.

ATTACHMENT O
CONTROL SYSTEM ACCEPTANCE TEST CRITERIA

[THIS ATTACHMENT WILL NEED TO BE MODIFIED BASED ON THE TYPE AND DESIGN OF THE FACILITY]

Final test criteria and procedures shall be agreed upon by Company and Seller no later than thirty (30) Days prior to conducting the Control System Acceptance Test in accordance Good Engineering and Operating Practices and with the terms of this Agreement. The Control System Acceptance Test may include, the following:

1. Ramp Rate Tests

   [TO BE DETERMINED.]

2. SCADA Tests

   [TO BE DETERMINED.]

3. Voltage regulation testing - Based on the IRS, test the Facility to hold the ___kV bus voltage as Company System conditions permit.

4. Curtailment Control Interface Tests: With the Facility online, test may include the operation and response to setpoint signals to test and ensure that the Facility decreases to the appropriate levels. Testing may also occur to confirm that when the curtailment is lifted, Facility is aware that the curtailment was lifted. Detailed testing steps and procedures will be agreed to by Company and Seller prior to said testing. As an example, Company may send the setpoint signal, verify that the Facility received the signal, determine the setpoint value the Facility received and determine where the Facility settled once it received the signal. Company may verify that the Facility did decrease to the level that was initiated on the EMS.

5. Anunciator Tests

   [TO BE DETERMINED.]

6. RTU testing to ensure correct operations (note: prior to testing with the actual breaker equipment described above, initial testing will most likely be performed at the RTU level) (The RTU is the interface between the EMS and the

physical equipment at the Site). Detailed scope and procedures will be agreed to by Seller and Company.

7. Analog outputs from Facility to Company:

   (A) Test in increments without the Facility on-line to determine what analog signals are observed (MW, MVAR, AMPS, KV) and appropriateness of same. (More RTU testing)

   (B) With the Facility on-line, at various generation levels, test to verify and ensure that what the Facility output shows is identical to the output shown on the EMS.

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